AFWAL-TR-80-2074

LEVEL *II* ②

TERRESTRIAL PHOTOVOLTAIC SYSTEM ANALYSIS

M. S. IMAMURA
R. GIELLIS
R. L. MOSER

MARTIN MARIETTA CORPORATION
P. O. BOX 179
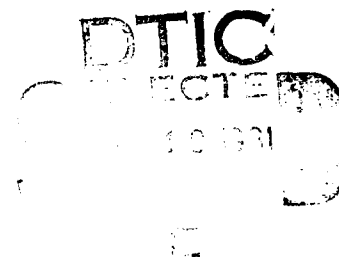*DENVER, COLORADO 80201*

DTIC

JULY 1980

TECHNICAL REPORT AFWAL-TR-80-2074
Final Report for period February 1979 to November 1979.

Approved for public release; distribution unlimited.

81 2 10 003

This technical report has been reviewed and is approved for publication.

RICHARD G. HONNEYWELL, 2Lt, USAF
Project Engineer
Energy Conversion Branch

ROBERT R. BARTHELEMY
Chief, Energy Conversion Branch
Aerospace Power Division

FOR THE COMMANDER:

JAMES D. REAMS
Chief, Aerospace Power Division
Aero Propulsion Laboratory

REPORT DOCUMENTATION PAGE	READ INSTRUCTIONS BEFORE COMPLETING FORM

1. REPORT NUMBER	2. GOVT ACCESSION NO.	3. RECIPIENT'S CATALOG NUMBER
AFWAL-TR-80-2074	AD-A094 827	

4. TITLE (and Subtitle)	5. TYPE OF REPORT & PERIOD COVERED
TERRESTRIAL PHOTOVOLTAIC SYSTEM ANALYSIS	Final, Feb 1979 — Nov 1979
	6. PERFORMING ORG. REPORT NUMBER
	MCR-80-583

7. AUTHOR(s)	8. CONTRACT OR GRANT NUMBER(s)
M. S. Imamura, R. Giellis, R. L. Moser	F33615-79-C-2001

9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS
Martin Marietta Corporation P.O. Box 179 Denver, CO 80201	Program Element 61102F Project 3145 Task 314524 Work Unit 31452407

11. CONTROLLING OFFICE NAME AND ADDRESS	12. REPORT DATE
Aero Propulsion Laboratory (AFWAL/POO) Air Force Wright Aeronautical Laboratories Wright Patterson Air Force Base, OH 45433	Jul 1980
	13. NUMBER OF PAGES
	117

14. MONITORING AGENCY NAME & ADDRESS(if different from Controlling Office)	15. SECURITY CLASS. (of this report)
	Unclassified
	15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

Approved for public release: Distribution unlimited

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

18. SUPPLEMENTARY NOTES

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Solar Energy Conversion
Photovoltaic Concentrators
Silicon Solar Cells
Terrestrial Solar Power

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

The purpose of this program was to evaluate the use of an actively cooled photovoltaic power system at Tinker Air Force Base, Oklahoma, which required both electrical and thermal energy. The thrust of the study was to identify a preliminary design of an actively cooled photovoltaic concentrator configuration including the necessary details of integrating it into the facility, and compare the cost of this system and that of the present energy sources. A conventional utility-connected arrangement was selected for the

DD FORM 1473 EDITION OF 1 NOV 65 IS OBSOLETE

Tinker AFB electroplating facility mainly because of simplicity in its implementation and availability of the inverter, which is the key component in the system. The system uses a direct energy transfer arrangement with a peak array power tracking inverter; no electrochemical storage batteries are used. The thermal energy distribution system interfaces directly with the plating tanks in the facility. The estimated initial installed cost of the combined photovoltaic/thermal system is $28 per Watt. The use of thermal energy for the plating tanks is costly ($3 per Watt) because of an extensive distribution system and use of exotic heat exchangers. One conclusion, therefore, is that an electric-only photovoltaic system is more cost effective.

Accession For		
NTIS GRA&I		X
DTIC TAB		
Unannounced		
Justification		
By		
Distribution/		
Availability Codes		
	Avail and/or	
Dist	Special	
A		

SUMMARY

A conventional utility-connected arrangement was selected for the Tinker AFB electroplating facility mainly because of simplicity in its implementation and availability of the inverter, which is the key component in the system. The system uses a direct energy transfer arrangement with a peak array power tracking inverter; no electrochemical storage batteries are used. The thermal energy distribution system interfaces directly with the plating tanks in the facility.

The most practical location for the photovoltaic arrays was determined to be the roof on the building adjacent to the plating facility. Sufficient roof area is available to install an array size of at least 300 kW.

The estimated initial installed cost of the combined photovoltaic/thermal system is $28 per watt. The use of thermal energy for the plating tanks is costly ($3 per watt) because of an extensive distribution system and use of exotic heat exchangers. One conclusion, therefore, is that an electric-only photovoltaic system is more cost effective.

The daily average power requirement of the electroplating facility at Tinker AFB is about 733 kW. Thus, the key driver for determining the power rating (i.e., sizing) for the "modularized" photovoltaic system is the availability of the inverter. A 50 kW system was identified as the baseline modular photovoltaic power system. However, it is pointed out that the overall cost of a much larger system, e.g., a 300 kW system can reduce the net cost per watt (in July 1979 dollars) of the key elements as indicated here:

Component	50 kW System	300 kW System
Solar Array	$10/W	$8/W
Inverter	$38/W	$1/W (different supplier)

The life-cycle cost analysis, based on the 50-kW system and considering present and future utility fuel cost, showed that the photovoltaic system is less economical than the conventional energy sources in capacity and energy displacement. However, if fuel costs in conventional power plants escalate at 16% per year or more over the 25-year life of the system combined with a reduction in photovoltaic system cost, the photovoltaic system would be economically justifiable in 1987.

1

PREFACE

This final report is submitted by Martin Marietta Corporation under contract F33615-79-C-2001. The effort was sponsored by the Aero propulsion Laboratory, Air Force Wright Aeronautical Laboratories, Wright-Patterson Air Force Base, Ohio, for the Air Force Logistics Office with Lt Richard Honneywell as Project Engineer in charge.[1] Mr. Matthew S. Imamura of Martin Marietta Corporation was technically responsible for the work. Mr. Roger Giellis of Martin Marietta Corporation performed system life-cycle cost analysis and the design and analysis of the thermal system. Mr. Robert L. Moser of Martin Marietta Corporation was responsible for the power conditioning equipment design and analysis. The work covered the period from February 1979 to November 1979.

.

CONTENTS

FIGURES

FIGURES

TABLES

SECTION I

INTRODUCTION

This study evaluated the use of an actively cooled photovoltaic power system for the manufacturing facility at Tinker Air Force Base, Oklahoma. The facility requires both electrical and thermal energy, the latter for electroplating. The study identified a preliminary design for an actively cooled photovoltaic concentrator configuration, included the necessary details of integrating the design into the facility, and compared the cost of the system with present energy sources. The system configuration was to be selected from designs that were reasonably well developed at the time of this study (February to November 1979). Specific study areas were as follows:

(a) Site isolation and weather data assessment.

(b) Survey of site facility requirements and constraints.

(c) Survey of development status, cost, and performance of systems capable of providing both thermal and electrical energies.

(d) Selection of nominal power rating and photovoltaic system configuration best suited for this Air Force application.

(e) Definition of a preliminary design and its performance.

(f) Projection of initial hardware and installation, maintenance, and labor, and life cycle cost.

(g) Cost comparison of the solar system and conventional system.

Background

Current events have brought the urgency of the national energy supply problem to the forefront once again. Gasoline prices in excess of one dollar per gallon are now common across the United States. Residents of the midwest and eastern states were shocked by a one-year 70% increase in fuel oil prices. This chaos in the energy markets is attributed to the following key factors:

(a) Iran's internal conflict, which nearly halted their oil production;

(b) Saudi Arabia reduced its oil output in mid-1979;

(c) OPEC raised its oil prices from about $12.70 per barrel to an average of $24 per barrel in 1979.

All these have been interesting data points on the short-term sensitivity of U.S. energy prices to uncontrolled foreign actions. Figure 1 shows energy price projections from 1977 to 2000 for Tinker AFB at Oklahoma City (Ref 1). The data points shown for 1979 are the actual prices, in 1977 dollars, currently being paid by Tinker AFB for electricity and natural gas.

The Battelle energy projections were based on three possible scenarios for crude oil pricing by the producing nations. In 1978 they considered the medium scenario as being the most probable. Unfortunately, by mid-1979 several key assumptions in their analysis had been invalidated by Arab actions and a 14% inflation rate in the United States.

Obviously, the events of 1979 have once again highlighted the vulnerability of the U.S. economy and security to outside influences; hence, the urgency for implementation of alternative energy sources has never been greater. Applications for high-technology options such as photovoltaic power systems, must be carefully reassessed with the national goal of long-range energy independence always in mind. Selected demonstration projects are needed soon to generate the valuable performance data base required to guide long-range planning and technology stimulations.

This report documents such an assessment for a promising solar technology—actively cooled photovoltaic concentrators as applied to an electroplating facility at Tinker AFB in Oklahoma City. The results and conclusions of this study could be applied to any industrial installation where electricity and low-grade thermal energy are required.

The Air Force's 10-year facility plan defined several goals for Air Force facility energy conservation programs. Two of these goals were relevant to the activities reported on in this study, specifically:

(a) To obtain one percent of Air Force installation energy by solar and geothermal means by 1985;

(b) To equip all natural gas heating units and plants with over five million per hour output with the capability to use oil or alternative fuel by 1982.

The impact of these goals can be fully appreciated when one considers that in fiscal year 1979 the Air Force spent about $500 million for facility energy supplies. Tinker AFB alone expends $9 million annually for electricity and natural gas. A one percent reduction in natural gas consumption at Tinker AFB would amount to roughly 23 million cubic feet of natural gas. This study has identified a possible displacement of 2.4 million cubic feet resulting from a 50 kW actively cooled photovoltaic system installed in the Tinker AFB electroplating facility.

1. D. Moore, and D. Locklin: A study to Determine the Desirability and Feasibility of New Alternative Energy Systems for the AFLC Installations. Battelle Columbus Laboratories, Contract F33601-77-40551, June 1978.

$18+

14

12

10

8

6

Delivered energy price, dollars/ million Btu

Electricity

Electricity
(Tinker AFB)

5

No. 2 fuel oil

4

Natural gas

Natural gas
(Tinker AFB)

3

Industrial

Utility

Wyoming coal

2

1

0
1977   1980   1985   1990   1995   2000

Range of
projected
prices in
year 2000
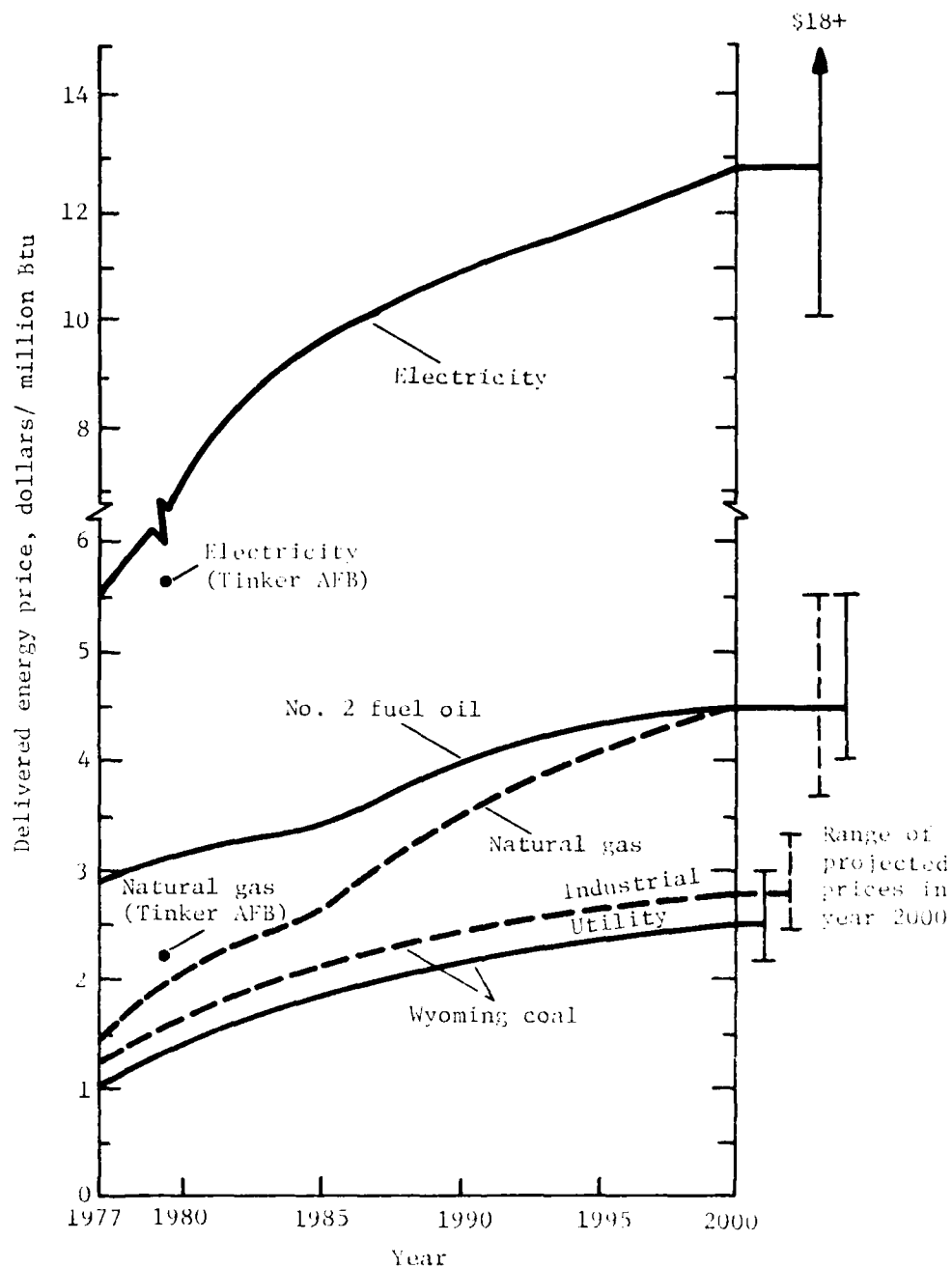
Year

Figure 1.   Energy price projections for medium scenario, constant
1977 dollars (from Ref 1).

On the electrical side, a one percent reduction in consumption at Tinker
would amount to 1.8 million kW hours per year.   The 50 kW solar photovoltaic
system would provide 0.08 million kW hours per year.

SECTION II

SITE REQUIREMENTS AND ANALYSIS

Site Analysis

Site Description - The Tinker AFB Electroplating facility occupies 38,000 square feet in Building 3001. Figure 2 shows the plating shop location and the surrounding buildings and land at the site. The plating facility includes 11 major plating lines consisting of 170 tanks distributed over the pit floor, which also contains the piping for the tanks. Figure 3 shows a typical plating line in the facility.

Existing Electrical Power Distribution - The plating tanks require low voltage, high current dc power. Each tank has its own rectifier. To minimize dc bus requirements, the rectifiers are located as close as possible to the plating tank as shown in Figure 4. Due to the corrosive atmosphere near the tanks, the rectifiers are totally enclosed. Temperature control for the rectifiers is provided by a water cooling loop. Power to the rectifiers is from the 460 Vac, 3-phase, 60 Hz utility line.

Most of the converters in the plating shop are Udylites, which are sealed, automatic solid-state units. A typical output characteristic is shown in Figure 5.

The plating shop works 24 hours per day, 365 days per year. The currents and voltages required by a plating tank cannot be supplied directly from the output of a solar photovoltaic array. A practical method of interfacing the dc output of a solar photovoltaic array is by using a 3-phase inverter to convert the unregulated dc voltage from the solar array to regulated 3-phase, 60 Hz, 460 Vac for power distribution to the plating facility.

A block diagram of the present plating facility's 270/480 Vac, 3-phase power distribution system is shown in Figure 6.

A preliminary breakdown of power consumption from the 480 Vac, 3-phase, 60 Hz for the plating facility bus was provided by engineering personnel. An estimate of the loads is shown in Table 1.

Existing Thermal Distribution System - The present tank heating system in the electroplating facility uses central plant-supplied medium temperature steam (250°F to 300°F) to directly heat the plating solutions and rinse tanks. This is accomplished by passing the steam through a submerged coil in the tank. Control is achieved with a temperature-regulated steam valve at each tank.

Once through the heating coil, the steam condensate is vented outside the facility, thus ensuring that no corrosive plating solutions could ever be inadvertantly returned to the central plant system. Figure 7 shows a simplified schematic of this existing tank heating system.
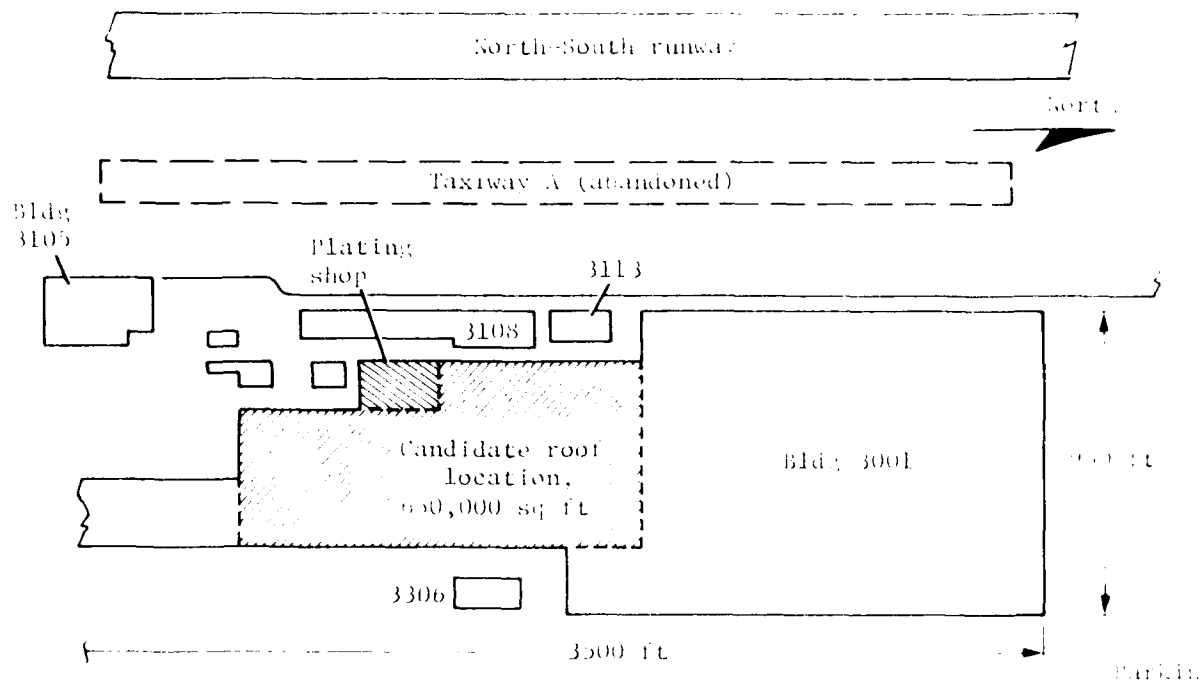
Figure 2. Electroplating facility location at Tinker AFB, Oklahoma City, Okl.
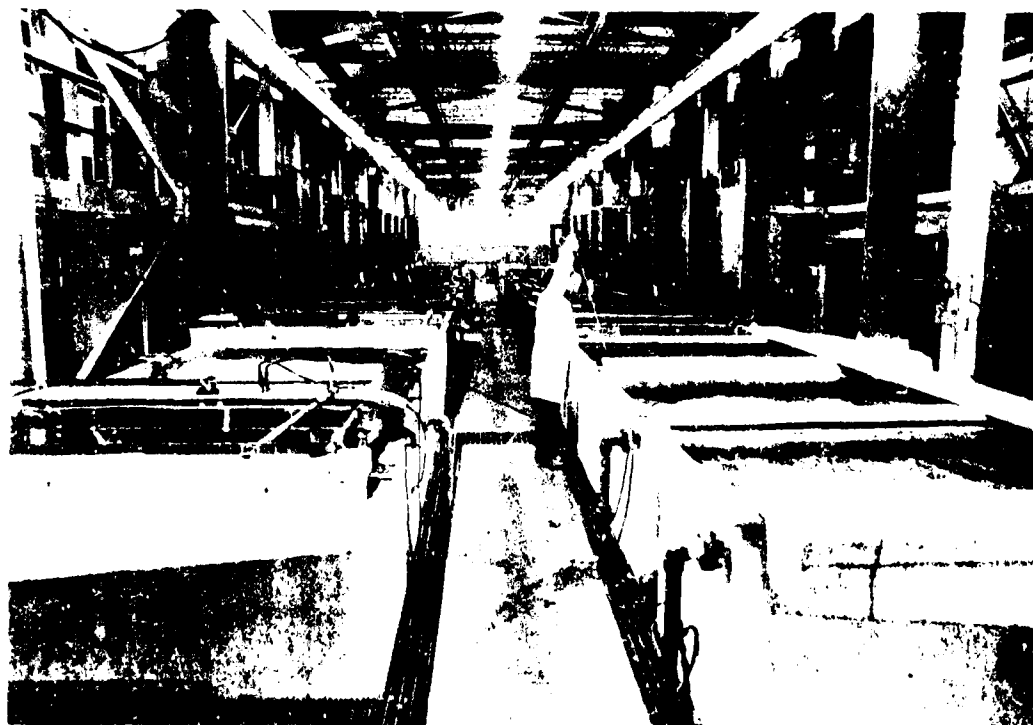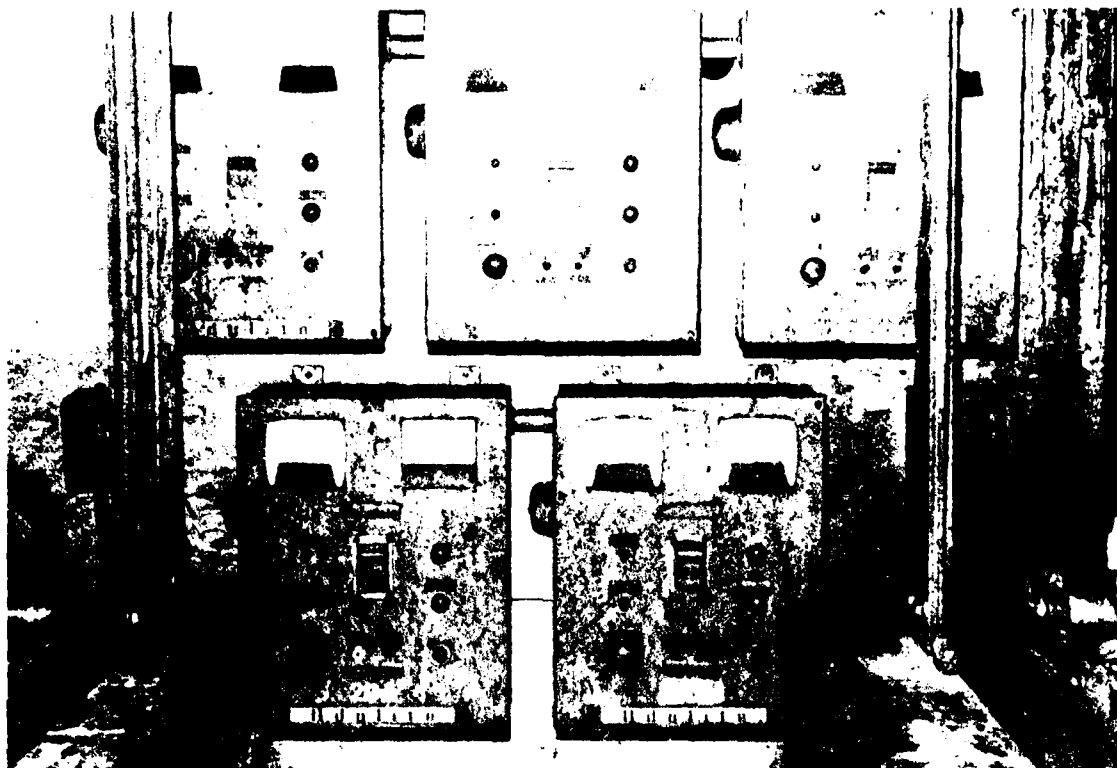
Figure 4. Typical ac-dc rectifier for each plating tank.
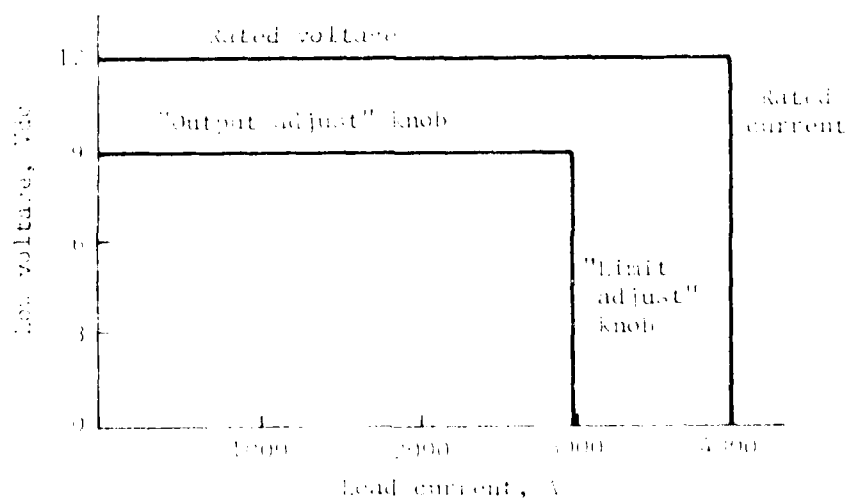
Figure 5. Typical constant voltage operation.
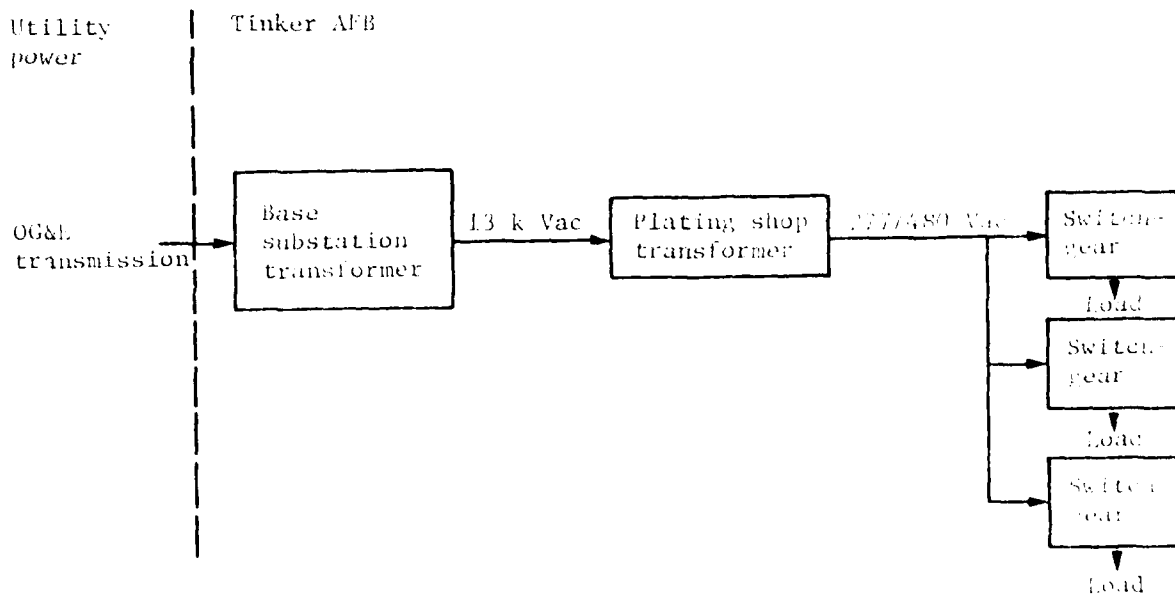
Figure 6. Present plating facility power distribution block diagram.

TABLE 1. ELECTRICAL CONSUMPTION AT THE ELECTROPLATING FACILITY, TINKER AFB

Load	Power, (kW[a])	Energy, (......)
Lights	100	2,400
Motors	100	2,400
Plating	533	12,792
Total	733	17,592
[a] 460 Vac, 3 phase, 60 Hz		
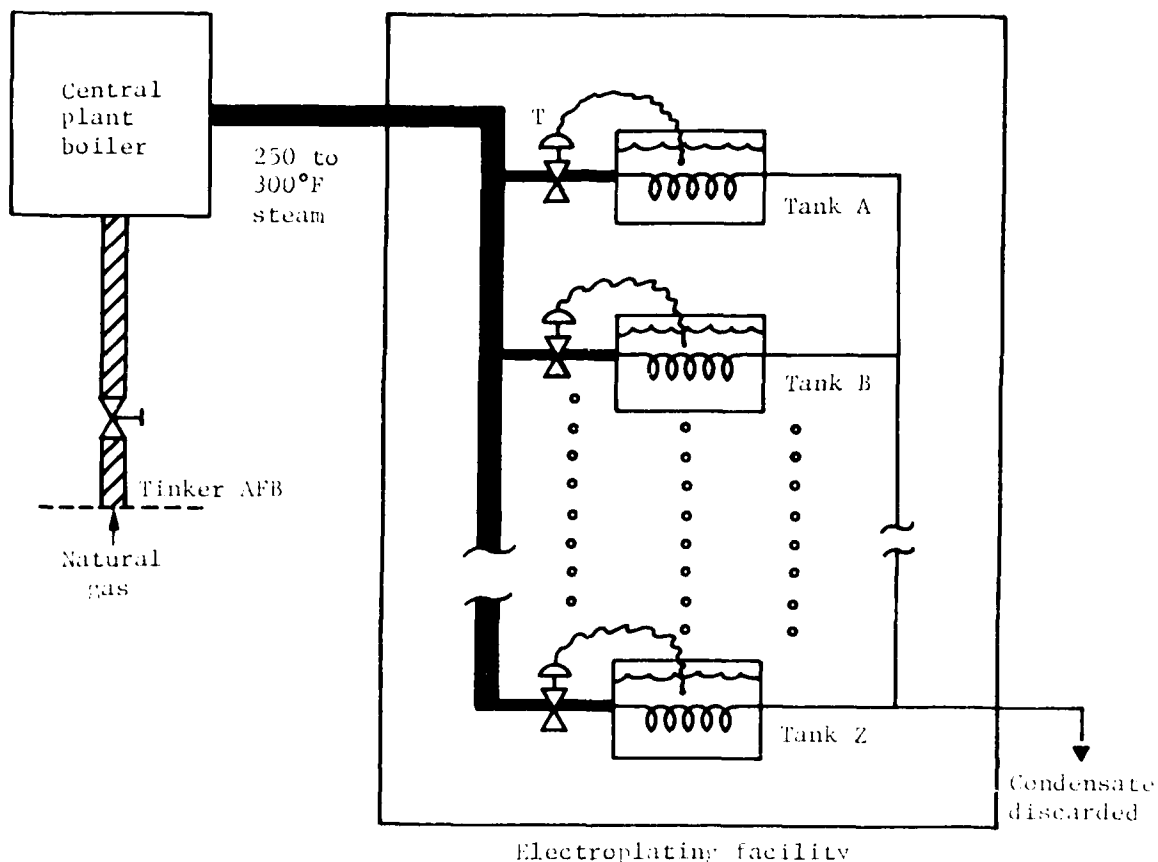
Figure 7.   Existing tank heating system at the Tinker AFB
electroplating facility.

Table 2 summarizes the daily thermal loads for the process lines in the
south half of the shop starting from the nickel plating line. These lines
were identified as reasonable candidates for solar heating due to their prox-
imity, which would minimize the cost and complexity of the solar distribu-
tion system. Inspection of Table 2 shows that the tank temperatures gener-
ally fall into two temperature ranges, 110°F to 135°F and 160°F to
195°.

The thermal loads shown in Table 2 were based on the Battelle estimates
(Ref 1) modified to account for insulation on the tank sides (the existing
tanks are uninsulated). A detailed analysis was conducted for the low tem-
perature tanks (i.e., 140°F) to quantify the load reduction. An insula-
tion thickness of 2 inches was used in the analysis. Results from that
analysis are presented in Table 3 for two typical tanks. Based on the annu-
al energy savings shown, the insulation is cost effective and we extended
the analysis to all tanks that are grouped in the south half of the shop
starting from the nickel plating line. In considering energy conservation
measures for AFLC, Battelle (Ref 1) recommended that the following criteria
be satisfied:

14

TABLE 2. DAILY THERMAL LOADS FOR TINKER AFB PLATING FACILITY

Process line	Temperature range (°F)	Net estimated heat loss[a] (Btu/Day x 10^6)
Chrome, 200 series	110-135	9.37
Nickel, 400 series	110-130	3.42
Nickel-cadmium, 800 series	110-130	4.68
Misc tanks, 900 series	110-130	0.88
	Low-temperature subtotal	18.36
		(5380 kW-hr/day)
Chrome Strip	160-185	9.08
Nickel-cadmium	170-190	5.53
Miscellaneous	180-195	3.60
	High-temperature subtotal	18.21
		(5330 kW-hr/day)

[a] Heat gains due to plating dissipation have been accounted for in computing net heat loss. Heat loss calculation assumed 2 inches of insulation on tank sides only.

TABLE 3. TANK HEAT LOAD REDUCTIONS FROM 2-INCH SIDE INSULATION

Tank	Configuration	Side loss (Btu/hr)	Bottom loss (Btu/hr)	Surface loss (Btu/hr)	Total loss (Btu/hr)	Annual savings (Btu)
No. 400 2' x 4' x 4' Vented 130°F	Existing	8,234		48,130	58,080	
	Insulated sides	2,940	1,716	48,130	52,786	46.3 x 10^6
No. 412 2' x 4' x 4' Not vented 120°F	Existing	7,060		16,930	23,980	
	Insulated sides	2,520	1,440	16,930	20,460	31.5 x 10^6

15

$$\frac{\text{Energy saved per year}}{\text{Initial cost}} = 23,000 \frac{\text{Btu}}{\text{yr}}$$

Hence, for the insulation on Tank 400 to be cost effective, the initial tank cost of $2,013 (i.e., $46.3 \times 10^6/23,000$) is expected. Tanks are assumed to be insulated before implementing the solar system.

The resulting total thermal load for each process line is presented in Table 3. These loads were used in our thermal analysis of the actively cooled photovoltaic system.

The above analysis was extended to all tanks that are grouped in the south half of the shop starting from the nickel plating line.

Current Energy Costs at Tinker AFB – Presently, all baseload electricity at Tinker AFB is purchased from the Oklahoma Gas and Electric Company (OG&E). This utility company has a capacity of 4700 megawatts of which 3200 MW is generated by natural gas and 1500 MW from coal. OG&E's long-term outlook for energy supplies depends heavily on new coal-fired plants. They have 30-year contracts to purchase coal in Gillette, Wyoming, however, these contracts allow for a 10% per year escalation in the base price for the coal. Rail transportation costs are increasing at 15% per year, so by the late 1980s the transportation costs alone will be a sizeable fraction of OG&E's total cost for fuel.

Natural gas is supplied to Tinker AFB by Oklahoma Natural Gas Company. All this gas is intrastate gas and hence unregulated in price.

Table 4 lists the current rates for electricity and natural gas at Tinker AFB, along with their expected escalation over the next 20 years. Operating costs for the plating shop loads discussed above are also given in Table 4.

Candidate Locations for Photovoltaic Array – Two site options were assessed for the installation of a photovoltaic array, which include (1) adjacent open land on the east edge of the airfield, and (2) the roof of Building 3001. The open land extends from the service road behind Building 3001 to an abandoned taxiway (see Figure 7). From discussions with the air base operations group it was apparent that existing regulations would not allow installation of any structures on the edge of the field, especially if they contained reflecting surfaces that would present a safety problem to incoming aircraft.

The roof of building 3001 is the only practicable location for a photovoltaic field. The plating shop roof is not acceptable because it is too lightweight and contains numerous ventilation exhaust stacks. However, the roof of Building 3001 adjacent to the plating shop is reasonably strong and a preliminary evaluation by the Tinker AFB civil engineering group concluded that some of the lighter photovoltaic arrays could be supported by the roof. Well over 15 acres of this roof are available for a photovoltaic installation (see Figure 7 and 8).

TABLE 4. ELECTRICITY AND NATURAL GAS ... ...

1979 rate data	
Electric energy	2.23¢/kW-hr
Electric demand	1.65¢/kW
Natural gas	1.93$/1000 cu ft

Expected escalation (real terms, not including inflation)		
	Electricity (%)	Natural gas (%)
1980 – 85	5.9	4.4
1985 – 90	2.4	6.1
1990 – 2000	1.6	2.5

1979 annual costs for plating shop operations	
Electric energy	$143,190
Natural gas	$ 39,818 (including water heating ... ...)
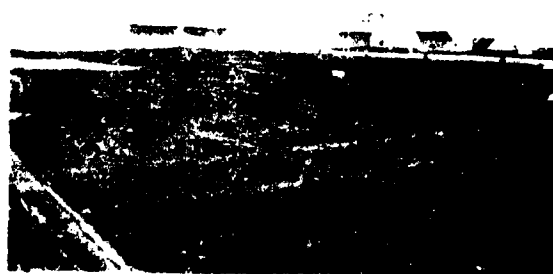
Details of the roof supporting structure are shown in Figure 9. The roof is a composite of metal decking, rigid insulation, felt subroof, and asphalt roofing material. This composite is supported by bridgework, which in turn is supported by 25-foot high steel columns (12WF25 lb) on 30-foot centers in the east-west direction and 60-foot centers in the north-south direction.

One serious reservation resulted from the civil engineering roof evaluation. They requested that the north-south spacing of array rows be constrained to the 60-foot column centers (see Appendix A). This results in very inefficient packing for the row-mounted linear candidate arrays.
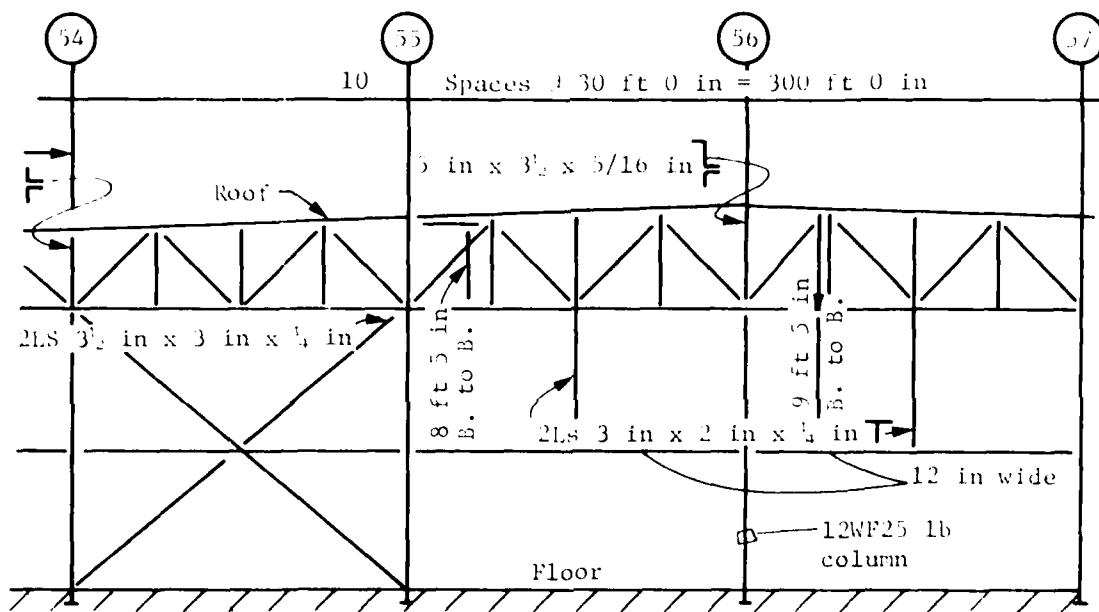
Figure 9. Roof supporting structure for Building 3001 adjacent to plating shop

Thermal Storage Location - Our site visit to Tinker AFB identified the lack of available space in the plating shop for a thermal storage tank as a potential problem. A roof location over the north end of the shop was suggested, however, the Tinker AFB civil engineering group suggested that the footings under the load-bearing walls could not support the weight.

An alternative location over the alley between buildings 3001 and 3108 was then evaluated. This approach would require construction of an expensive steel frame. This location is not preferred due to the long piping runs (over 200 feet, one way) required to reach the array field.

No practicable location has been identified for the thermal storage tank; consequently, the possibility of using the mass of the plating solutions directly as the thermal storage mechanism was evaluated and considered to be a workable approach. Results of these calculations are found in Section IV.

Survey of Existing Insolation Data Base - Measured direct normal radiation is not available for Oklahoma City; however, much progress has been made by DOE in generating reasonable estimates of the availability of direct normal radiation for solar applications The survey of insolation data sources for Oklahoma City is summarized in Table 5.

Table 6 lists the mean daily total hemispheric radiation available at Oklahoma City. These data were derived from regression models by the National Oceanic Atmospheric Administration (NOAA) as part of their Solar Meteorology data collection effort. Unfortunately, total radiation is of little value for the sizing of solar concentrators because the ratio of diffuse to direct radiation is not known.

For the past several years Sandia Laboratories have been developing techniques for computing solar radiation availabilities to different types of collectors in various geometries. Figure 10 contains a rough map of average annual direct-normal insolation, which was taken from the work of E. C. Boes (Ref 2), and revised to include the new SOLMET (Ref 3) direct normal data base which was developed by Randall and Whitson of the Aerospace Corporation (Ref 4) and is available for 26 cities from the National Climatic Center in Asheville, North Carolina. Unfortunately, Oklahoma City is not one of these 26 cities.

TABLE 5. INSOLATION DATA SOURCES FOR OKLAHOMA CITY

Source	Type	Utility for Tinker AFB analysis
SOLMET/NOAA[1]	Hourly horizontal global radiation. Modeled data based on cloud cover regressions.	Too detailed for preliminary design purposes. Could be used to check clearness numbers for SIM and SOLCOST.
OLMET/NOAA[2]	Average daily horizontal global radiation, by month. Based on 1 above.	Required by SOLCOST to compute average monthly thermal output.
Climatic Atlas/NOAA[3]	Percent of possible sunshine, average by month.	Required by SIM to estimate monthly insolation.

References:

1. SOLMET, Volume 2 - Hourly Solar Radiation - Surface Meteorological Observations. TD-9724, NOAA National Climatic Center, February 1979.

2. Input Data for Solar Systems. Report prepared for DOE by NOAA National Climatic Center, Agreement E (49-26)-1041, November 1978.

3. Climatic Atlas of the United States. NOAA National Climatic Center, 1968.

TABLE 6. MONTHLY SOLAR INSOLATION AND TEMPERATURES FOR OKLAHOMA CITY

Station: Oklahoma City					State: OK		
Station number: 13967 Latitude: 35.24S Longitude: 97.36W Elevation:							
Normal temperature (deg F)[a]			Normal degree days[b]		Total hemispheric Mean daily Solar radiation		
Month	Daily maximum	Daily minimum	monthly	Heating	Cooling	Btu/ft2	KJ/M2	Langley
Jan	47.6	26.0	36.8	874	0	800.9	9089.0	217.2
Feb	52.6	30.0	41.3	664	0	1055.0	11973.0	286.2
Mar	59.8	36.5	48.2	532	11	1400.1	15890.0	379.1
Apr	71.6	49.1	60.4	180	42	1725.4	19581.0	468.1
May	78.7	57.9	68.3	36	138	1918.1	21768.0	520.1
Jun	87.0	66.6	76.8	0	354	2143.9	24331.0	581.5
Jul	92.6	70.4	81.5	0	512	2128.4	24155.0	577.2
Aug	92.5	69.6	81.1	0	499	1950.3	22134.0	529.2
Sep	84.7	61.3	73.0	12	252	1554.2	17638.0	421.1
Oct	74.2	50.6	62.4	148	68	1232.6	13989.0	334.1
Nov	60.9	37.4	49.2	474	0	901.0	10225.0	244.4
Dec	50.7	29.2	40.0	775	0	725.4	8233.0	196.1
Ann	71.1	48.7	59.9	3695	1876	1461.3	16584.0	396.4

[a] Based on 1941-1970 period   [b] Base 65°F

Solar Insolation Model, SIM - An analytical prediction model was used to define solar insolation characteristics for Tinker AFB location rather than empirically recorded weather and insolation data. The reasons are:

(a) The SIM model is inexpensive to run, and has tremendous versatility for system sizing and performance assessment purposes.

(b) Long-term continuously recorded weather and insolation data are not available for the Tinker AFB site.

(c) Weather data based on a statistical average over several years (e.g., Aerospace weather tape) has limited value in parametric system performance analyses.

---

2. E. C. Boes et al.: Availability of Direct, Total, and Diffuse Solar Radiation to Fixed and Tracking Collectors in the USA. SAND 77-0885 Sandia Laboratories, Albuquerque, NM (1977).

3. SOLMET - Hourly Solar Radiation - Surface Meteorological Observations: Users Manual, TD-9724, prepared for the U.S. Department of Energy by the National Climatic Center, Ashville, NC, Dec 1977.

4. C. M. Randall, M. E. Whitson, Jr: Hourly Insolation and Meteorological Data Bases Including Improved Direct Insolation Estimates. Aerospace Report ATR-78 (7592-1), SAND 78-7047, December 1977.

An insolation database was established at the Martin Marietta facility during 1976, and these data was used in the analysis to generate an accurate solar insolation model. Daily data for direct normal insolation were taken once per month for seven months. Data were not available for April, July, August, October, and November and, for these months, interpolation was used to provide model parameters. Cloud and temperature information for Oklahoma City was taken from the National Climatic Atlas.

SIM requires three types of input data: location, time, and weather. These data, defined in Table 7 are read once per day by SEPS. The fundamental equation for the solar insolation model is:

$$I = C_n I_o(d) \exp(-\tau/\cos z)$$

where

I = Normal incident clear-sky irradiance

$I(d)$ = Extraterrestrial solar irradiance on day d.

τ = optical depth

z = Solar zenith angle

C_n = clearness number

Using an extra terrestrial solar constant of 1353 W/m² allows equation 1 to be simplified to

$$I = C_n 1353 (1-K_d) \exp(-\tau/\cos z)$$

In the model, K_d and τ are contained in lookup table with separate values for each month, and interpolation is used to obtain values for intermediate days. The clearness number, which is a curve-fitting constant, was used to fit the model to available weather data at the Tinker AFB site.

Solar position angles are derived in the program from the relations

$$\cos z = \sin \alpha_e = \cos L \cos \delta \cos h + \sin L \sin \delta$$

and

$$\sin \alpha_a = \frac{\cos \delta \sin h}{\cos \alpha_e}$$

where α_a is the solar azimuth angle, true south being zero, and positive angles representing afternoon. The hour angle, h, and the solar declination angle, δ, are dependent on time-of-year as shown in Figure 11 and must also be modeled. The hour angle is defined by

$$h = 15 (t-12.00)$$

where ET is the equation of time given by

$$ET = -(0.12357 \sin b - 0.004289 \cos b + 0.153809 \sin 2b + 0.060783 \cos 2b)$$

and

$$b = \frac{(d-1) \cdot 360°}{365.24}$$

describes the angular fraction of a year represented by a particular day. The solar declination angle is defined by

$$\sin \delta = \sin (23.44383°) \sin \epsilon$$

where

$$\epsilon = a + 0.4087 \sin a + 1.8724 \cos a - 0.0182 \sin 2a + 0.0083 \cos 2a$$

and

$$a = 279.9348° + \frac{(d-1) \cdot 360°}{365.242}$$

represents the angular fraction of the year at a particular day for the declination angle calculation.

In addition to accurate insolation calculation, SIM can also be programmed to handle complex cloud patterns. Because only direct normal insolation is of interest in this study, the insolation is considered either full-on or full-off depending on whether clouds are present. Cloud cover is programmed each day by specifying a total cloud amount (35%) and a cloud cover period (6 am to 11 am).

The total cloud amount is adjusted according to the cloud cover period. Thus, specifying 35% cloud cover and a 6-hour cloud cover period on the equinox would result in 70% cloud cover during the 6-hour period. Cloud and temperature data are also shown in Figure 11.

Cloud data are automatically adjusted for actual sunrise and sunset by entering cloud cover time before sunrise and after sunset. The computational flow within SIM, shown in Figure 12, shows that day-dependent data are calculated only once at the beginning of the day to increase program efficiency.

SIM model performance is shown in Figure 12 compared to the data base at the Martin Marietta facility for September 21. As mentioned earlier, the clearness numbers used in the model were selected to fit the output to the measured data.

Figures 13, and 14, and Table 8 depict the insolation profiles at Tinker AFB site in the months of June and December, respectively.

Survey of Existing Weather Data Base - Weather records for Oklahoma City date back into the late 1890s. Table 9 lists the weather normals and extremes which have been recorded over the years at Oklahoma City.

(Rough sketches from seasonal charts and revised SOLMET
data in SAND 77-0885, Availability of Direct, Total & Diffuse
Solar Radiation for Fixed and Tracking Collectors in the USA,
Rev 1/30/78.)

Figure 10. Average annual direct normal insolation (1000 Btu/ft^2)

TABLE 7. SIM INPUT DATA

Location

  LOCATN - Location Description (Hollerith)
  XLAT - Latitude, Degrees (+ North, - South)
  XLON - Longitude, Degrees (+ West, - East)

Time

  TZN - Time Zone Number (MST = 7)
  MON - Month Number (January + 1)
  IYEAR = Year
  DST - Daylight Saving Time Indicator
  LEAPYR = Leap Year Indicator

Weather

  NUMCL - Cloud Cover (%)
  ISTART = Beginning of Cloud Cover Period (Time)
  IEND = End of Cloud Cover Period (Time)
  TAMB = Mean Daily Temperature (°C)

23

Figure 12. SIM flow diagram

TABLE 8.   DIRECT NORMAL INSOLATION WITH CLOUDS FOR TRACKING
ARRAYS AT TINKER AFB

Month	Mean (percentage) possible sunshine	Clearness number	Direct normal energy kW-hr/m²
Jan	59	0.90	141.2
Feb	61	0.84	148.6
Mar	63	0.84	184.0
Apr	63	0.85	192.6
May	65	0.83	201.7
Jun	73	0.86	222.1
Jul	75	0.83	229.7
Aug	77	0.79	227.0
Sep	69	0.85	182.1
Oct	68	0.87	176.4
Nov	60	0.86	146.4
Dec	59	0.90	133.7
			2,185.7 kW-hr/m²-yr

A - Solar azimuth angle
B - Direct normal insolation
C - Solar elevation angle
D - Integrated energy

A - Solar azimuth angle
B - Direct normal insolation
C - Solar elevation angle
D - Integrated energy
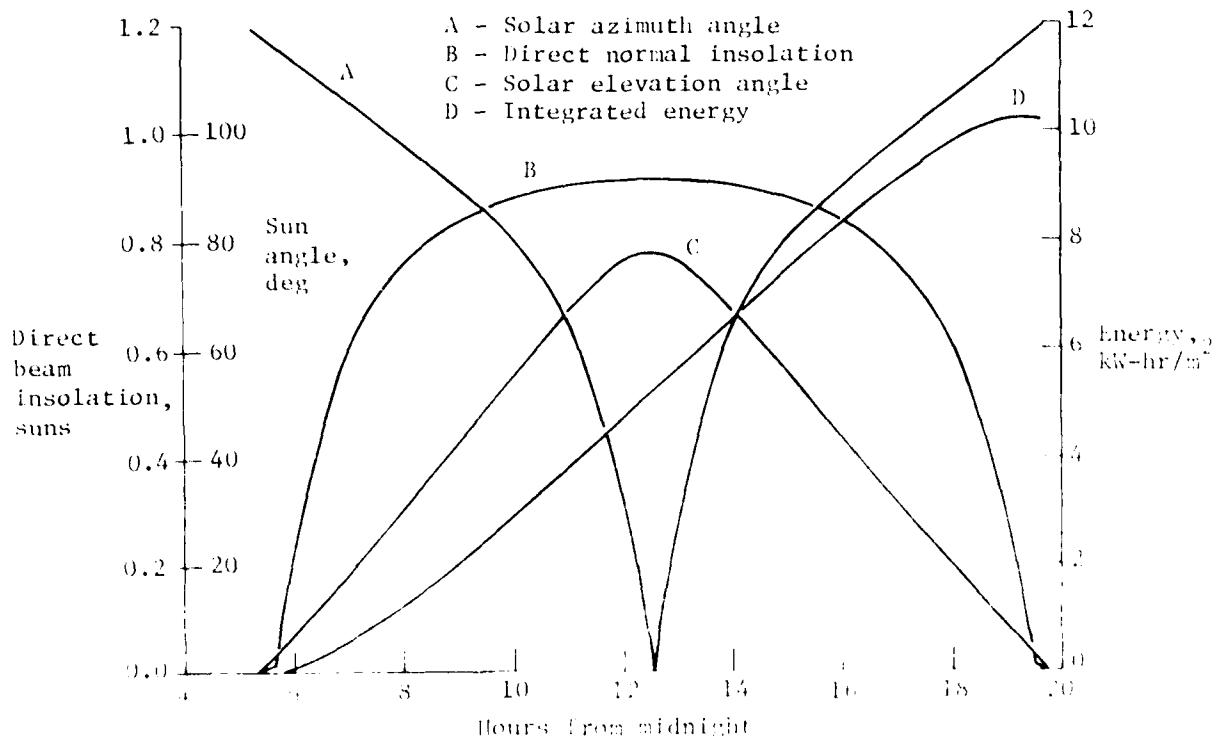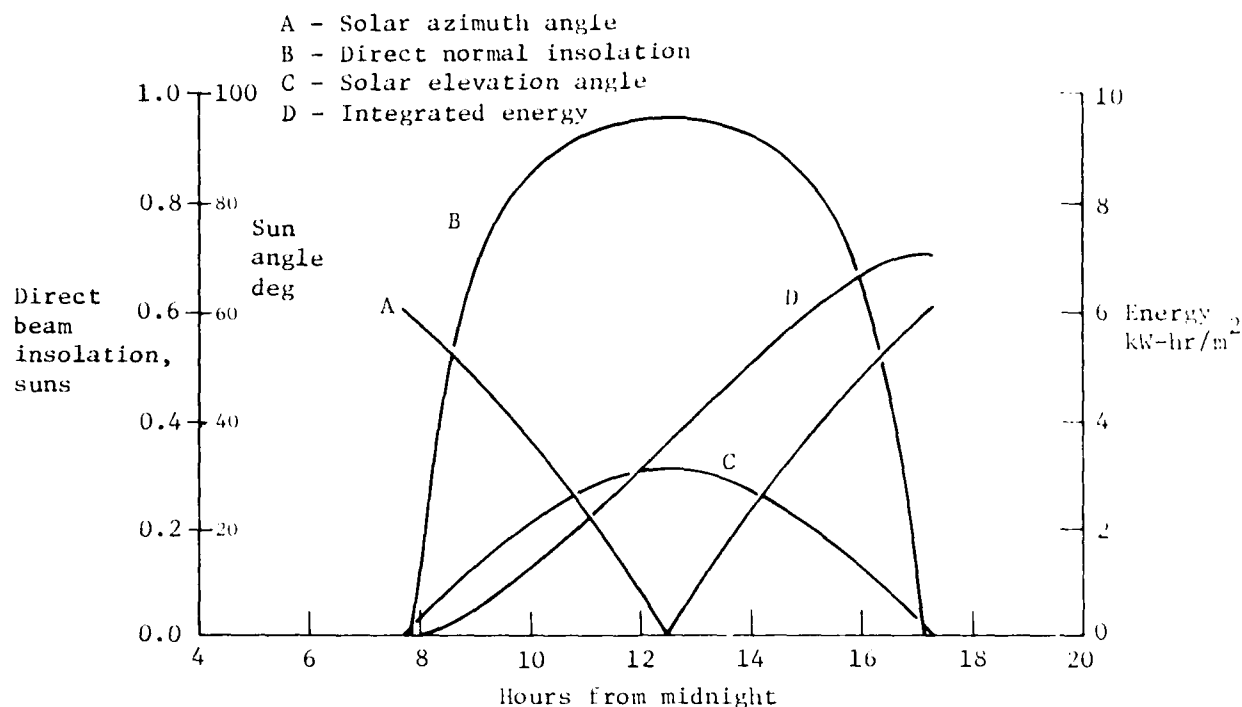
Figure 14. Insolation profile for December 21 at Tinker AFB site.

TABLE 9. WEATHER NORMALS AND EXTREMES FOR OKLAHOMA CITY, OKLAHOMA

Parameter	Normal	Extreme
Maximum temperatures	92.5°F (Aug) 67 days/yr 90°F 11 days/yr 100°F	113°F
Minimum temperatures	27°F (Jan) 1 day/yr 0°F 80 days/yr 32°F	-17°F
Wind speeds	15 mph from SSE	87 mph[b]
Rain	31 inches per year	8.4 Inches/24 Hours
Snow	Less than 10 inches per year	11.3 Inches/24 Hours
Freezing precipitation (hail, sleet)	(Not available in summary)	
Thunderstorms	51 per Year	
Relative humidity	54 to 80	96 to 80 (Annual)

Notes:
[a] Oklahoma Gas and Electric Co. design temperature high to
low data.
[b] OG design for 3 inches of ice, added to an assumed
40 mph wind speed.

SECTION II

SURVEY OF CANDIDATE PHOTOVOLTAIC CONCENTRATORS

The key objective for this task was to assess the development status of photovoltaic concentrators that are capable of delivering both electrical and thermal energy to the system loads. Initial costs and performance characteristics for the various concentrators were to be compared in the survey.

Overview of Photovoltaic Concentrators

The general collector geometries suitable for solar concentration are shown in Figure 15. Table 10 summarizes the established technology in concentrating collector systems in terms of concentration ratio and the required types of optics and tracking configurations. In recent years development work on the photovoltaic systems has centered around the following four concentrator types:

(a) Line-Focus Reflective Troughs,

(b) Point-Focus Reflective Dishes,

(c) Line-Focus Fresnel Lenses,

(d) Point-Focus Fresnel Lenses.

Table 11 presents a comparison of the advantages and disadvantages for the above four concentrator systems. The leading optical concentrators now are point-focus and line-focus Fresnel lenses.

Development Status of Photovoltaic Concentrators

On-Going Photovoltaic Concentrator Programs - The survey reviewed 12 concentrators in various stages of development. Table 12 presents a summary of the development status for all 12 developers contacted in our survey. All were participants in Sandia Laboratories' PRDA-35 (Photovoltaic Research and Development Application) phase one activity and five were awarded phase two contracts for fabrication and installation of their application experiments. The PRDA-35 developments will be discussed in detail in the following paragraphs.

TABLE 10. PHOTOVOLTAIC CONCENTRATOR SYSTEM TECHNOLOGY

Organization	Electrical power	Cooling	Concentration ratio**	Optics	Tracking
AAI, Inc	10 kW	Active	200:1	Parabolic mirrors	2-axis
Accurex	3.5 kW	Active	36:1	Parabolic cylinder	1-axis
Honeywell	10 kW	Active	40:1	Parabolic mirrors	2-axis
Martin Marietta*	10 kW	Passive & active	40:1	Fresnel lens, circular	2-axis
RCA	300 W	Passive	400:1	Fresnel lens, circular	2-axis
E-Systems	27 kW	Active	25:1	Fresnel lens, linear	1-axis

*Actively cooled system being developed.   **Geometric

The Department of Energy is continuing to fund selected projects under their Photovoltaic Concentrator Technology Development program. Their objective is to develop low-cost long-life PV concentrator arrays that can be commercialized at a price of $0.70 per watt or less by 1986 (factory price in 1980 dollars) or $2.80 per watt or less in 1982. Projects currently receiving funding include:

(a) Honeywell's sagged-glass parabolic-trough reflector;

(b) Martin Marietta's point-focus Fresnel concentrator,

   (1) a second generation concentrator involving 100 to 200 concentration ratio;

   (2) actively cooled concentrator, 2.2 kW at 33 concentration ratio.

(c) E-System's low-cost extrusion/embossing process for a linear Fresnel lens.

The most significant photovoltaic concentrator power system project initiated in 1979 is the world's largest stand-alone photovoltaic power plant in Saudi Arabia. Under the SOLERAS (Solar Energy Research American and Saudi agreement between the U.S. and Arabian Joint Commission on Economic Cooperation), the project was initiated to build and install a 350-kW photovoltaic system. After evaluation of twenty proposals, a 17-man team headed by the Institute of Solar Energy Research Institute in conjunction with
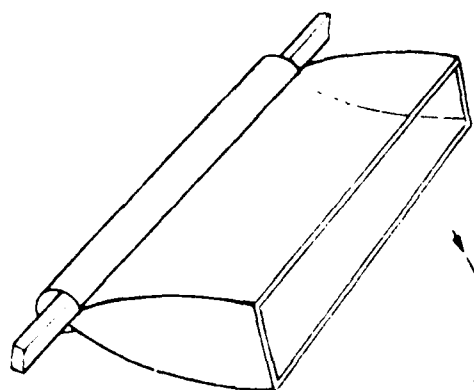
Compound parabolic systems   Parabolic dish   Parabolic trough
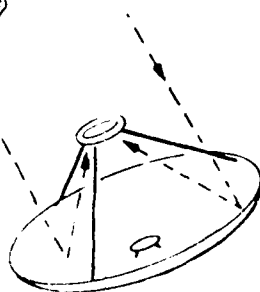
Sun's rays
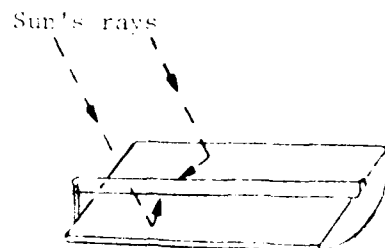
Solar cells mounted on flat surface

Faceted reflectors
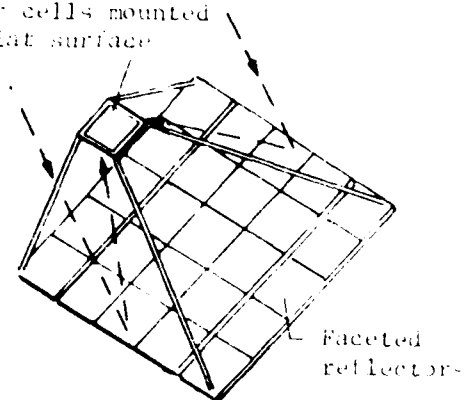
Faceted parabolic
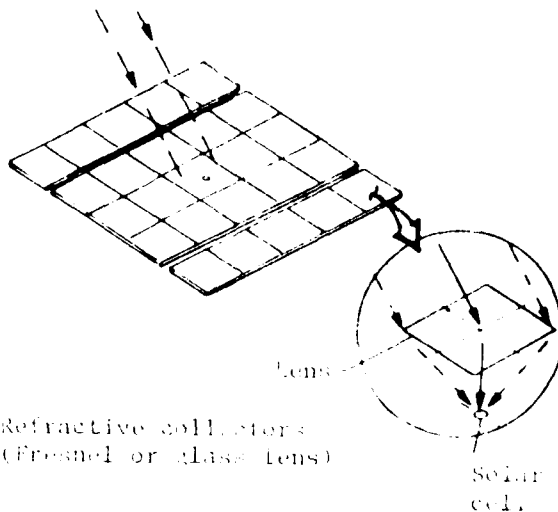
Refractive collectors (Fresnel or glass lens)

Lens

Solar cell

Sunlight

V-trough system

Sun's rays

Solar collector

Heat loop

Solar heat absorber
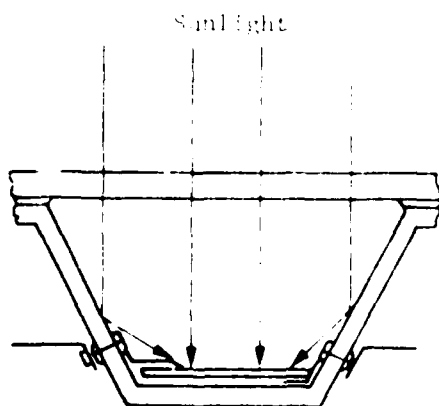
Photovoltaic cells
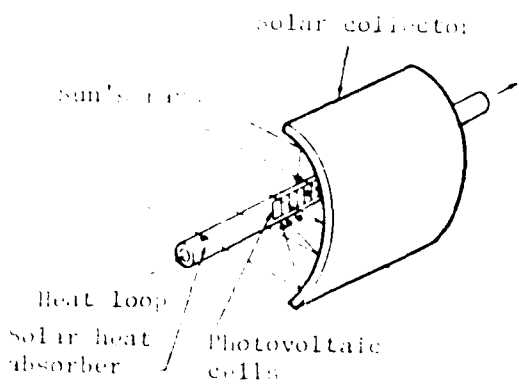
Integrated photovoltaic-thermal solar concentrating collector

Figure 1. Various concentrator collector types.

To sun

Angular region
of acceptance

Focused
light

Secondary
mirror

Primary
Mirror

Array

Cassegranian system

S ←————————————→ N

Combination parabolic troughs and V-collector

Concentrated sunlight
from paraboloid

Entry
window

Vacuum

Secondary
concentration

Coolant

Radiator

Photovoltaic
cell layer

Mirror

Thermophotovoltaic conversion

Incident light

Solar array
target

Rotation

Pivot
point

Reference
circle

Fixed reflector rotating target

Concentrator

Thermal
storage
tank

Radiator
valves

Hot water

Heating

Cooling

Light

Heat
Sink

Fan

SI cells

Pump

dc   ac

Tracking

PPU

Watt
meter

Home ac
loads

Utility system

High-intensity solar energy system

Figure 15.   Various solar energy concentrating systems (concluded)

TABLE 11. PV CONCENTRATOR COMPARISON

Concentrator type	Advantages	Disadvantages
Point-focus Fresnel lenses	High concentration possible. Single cell per lens. Lens provides weather protection; tested outdoors for 6 years with very little degradation. Considerable design flexibility; various modular designs. Forming of plastic well developed. Maintenance is easiest. Passive cooling is easy.	Two-axis tracking is required.
Linear-focus Fresnel lenses	Can be rolled. Lens provides weather protection. Passive cooling is straightforward.	Limited concentration. Requires uniform flux along receiver. Cell-to-cell spacing losses. Two-axis tracking required.
Reflective troughs	Considerable development exists under solar thermal program. Readily applicable to combined PV/thermal. Can use one or two-axis tracking.	Limited concentration. Cell-to-cell spacing losses. Receiver shading losses. Requires uniform flux along receiver. Difficult to clean surfaces. Passive cooling is difficult. Weather-resistant reflectors not well developed.
Reflective dishes	High concentration possible.	[illegible]

Arabia awarded the contract in December 1979 to Martin Marietta Corporation. Martin Marietta's passively cooled point-focus concentrator array, complete with 2-axis tracking system and necessary structures and foundations, was slightly below $10/W as compared to $10 to 13 for the flat-plate arrays. This suggests that if an actively cooled system is not required for applications like the Tinker AFB, concentrator systems are competitive and should be considered as candidates also.

TABLE 12. STATUS OF ACTIVELY COOLED PV CONCENTRATORS.

Contractor	Type	Status
AAI	Linear trough, 40X	Development dropped
Acurex	Linear trough, 36X	Prototype built and tested
BDM	Linear trough, 36X	Prototype built and tested
E-Systems	Linear Fresnel, 25X	Prototype built and tested
GE	Linear trough, 34X, turntable	Prototype built and tested
Honeywell	Linear trough, 45X, pedestal	Sandia funding; will build and test 4-?? module by Oct 1979
ITC	Linear trough, 36X	One prototype module tested
Kaman	Circular Fresnel, 32X, pedestal	Development continues in-house
Martin Marietta	Circular Fresnel, 40X, pedestal	Sandia funding; design under way; will build and test 2.2-kW array, Jan 1980
Motorola	Cassegrain	PRDA winner this size; could consider as converter?
Solarex	Linear trough, 20X	Prototype build and tested
Varian	Point-focus circular Fresnel, 400X	Design stage only

PRDA Winners:	Acurex, 85 kW	E-Systems, 25 kW
	BDM, 47 kW	GE, 117 kW
		Motorola, 2.3 kW

SOLERAS project winner: Martin Marietta Corporation, ...

PRDA-35 Activity - Phase 1 of DOE's PRDA-35 Concentrator Applications Experiment Project ended in mid-1979. Seventeen contractors participated in the Phase I studies. Eleven of the applications used actively cooled concentrators. Table 13 provided by Sandia Laboratories gives a comparative overview of the key parameters and technical approaches employed by the various system developers.

TABLE 13. PRDA-35 PROJECT SUMMARY INFORMATION

[illegible]

Four awards for PRDA-35 Phase II activity (fabrication and installation) were negotiated for applications with actively cooled concentrators. The total funding committed to these projects is $12.2 million. Most installations will be operational in 1980 with operational performance monitoring planned for three years after system startup.

TABLE 13. PRDA-35 PROJECT SUMMARY INFORMATION (CONCL)

The winning PRDA-35 projects included:

Acurex   Parabolic trough, 85 kW

BDM   Parabolic trough (built by Solar Kinetics), 47 kW

E-Systems   Linear Fresnel, 27 kW

General Electric   Parabolic trough, 325 kW

Figure 16 shows some of the concentrators undergoing development in the PRDA and Concentrator Technology Development programs.

Other Development Activity – Sandia Laboratories is evaluating proposals for the development of concentration optics in the range of 400X to 1000X. All concepts to be developed in this concentration range are expected to use active cooling. Some of the prototype modules will use low resistance silicon cells manufactured by Microwave Associates, which demonstrated efficiency of 23.5% at 40°C and 1000 suns, and GaAs cells with efficiency as high as 28.5% under similar conditions.

Performance and Cost Comparisons for Photovoltaic Concentrators

PRDA-35 Performance Projections Normalized to Tinker AFB – Several of the PRDA-35 contractors estimated their annual electrical and thermal performance using hour-by-hour computer simulations. We normalized these estimates to the Tinker AFB site conditions in an attempt to compare the electrical performance of the concentrators.

The thermal performance, however, could not be normalized in a similar manner because the thermal subsystems varied significantly for each PRDA application.

The normalization procedure for the electrical performance data was based on the following relations:

$$Q_n = \frac{N_{e, \text{Tinker}}}{N_{e, \text{PRDA}}} \times \frac{I_{\text{Tinker}}}{I_{\text{PRDA}}} \times Q_{\text{reported}}$$

where

Q_n = Normalized annual electrical output for Tinker conditions, kW-hr/m^2 -yr

Q_{reported} = Reported electrical output for PRDA applications, kW-hr/m^2 -yr

$N_{e, \text{Tinker}}$ = Cell efficiency for Tinker conditions, i.e., cell temperature = 75°C

$N_{e, \text{PRDA}}$ = Cell efficiency for PRDA design point conditions

I_{Tinker} = Available direct normal insolation at Tinker, 2185 kW-hr/m^2-yr

I_{PRDA} = Reported direct normal insolation for PRDA location, kW-hr/m^2-yr

A 0.5 percent change in electrical efficiency per 1°C change in cell temperature was assumed in the normalization process. The resulting performance comparisons are shown in Table 14. The range of projected performance is relatively close, 116 to 138 kW-hr/m²-yr. The total array efficiency ranges between 7.5 and 11.4%.

GE Performance Comparisons - Sandia currently has General Electric under contract to assess production processes for concentrating arrays. Key technical issues being addressed by GE include:

(a) Relative importance and cost potential of recent and most attractive array concepts;

(b) Best optical approach, i.e., Fresnels, troughs, dishes;

(c) Impact of turntable mounting of Fresnels and dishes;

(d) Determination of design uncertainty factors.

TABLE 14. PERFORMANCE COMPARISONS FOR PRDA-35 PV CONCENTRATORS

System	Location	Annual net electrical performance, (kW-hr/m²)	Design point cell temperature (°C)	Design point electrical efficiency (percent)	Normalized electrical performance	Annual net thermal performance	Total performance
Acurex	Hawaii	116					
Sci	Albuquerque	150			11		
	Dallas	133					
	Grande						
Honeywell							

*Normalized to ... conditions.

Figure 16 shows the candidate array concepts GE is evaluating in their study, which will be completed in December 1979. Table 15 presents some preliminary performance and cost comparisons from the GE study. Their early results indicate that high-concentration Fresnel lens, point focus and line focus, have the highest relative performance and cost potential, followed by medium-concentration Fresnel lens. They also concluded that point-focus Fresnels have the best optical approach for photovoltaic applications.

Measured Performance Data for Photovoltaic Concentrators - To date, very little measured performance data have been published by the concentrator developers. Table 16 summarizes the measured electrical and thermal performance data that were reported in the PRDA-35 Executive Summaries.
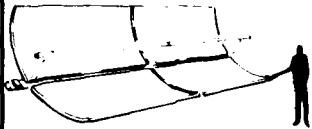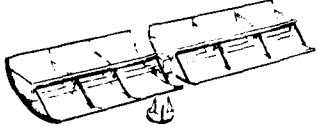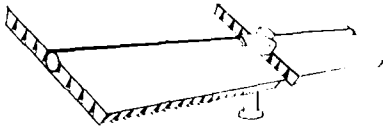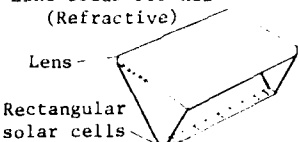
Concentrator concept	Concentrator type	Developer/ tracking
		BDM/Solar Kinetic Accurex 1-axis
Parabolic Trough		GE 2-axis
		Honeywell 2-axis
Point Focus Fresnel / Circular solar cell		Martin Marietta 2-axis
		Kaman Sciences 2-axis
Line focus Fresnel (Refractive) / Lens / Rectangular solar cells		E-Systems 1-axis plus adjustable tilt

Figure 16. Various photovoltaic concentrators developed under PRDA-35 (Sandia Laboratories).

TABLE 15. ARRAY CONCEPT COMPARISON, PRELIMINARY GE RESULTS

Array concept	Peak W/m²	Annual kWh/m²	FOB factory $/m²	Total installed $/m²	FOB factory		Total installed	
					$/W	$/kWh	$/W	$/kWh
High-concentration Fresnel (Si/GaAlAs)	169	400	277/383	422/529	1.65/2.25	.70/.85	2.50/3.15	1.0 1.5
Passive linear Fresnel	118	300	342	447	2.90	1.15	3.80	1.50
Passive circular Fresnel	116	300	334	460	2.90	1.10	3.95	1.55
Enclosed dish	83	209	219	335	2.65	1.05	4.05	1.60
Active circular Fresnel	114	275	303	448	2.65	1.10	3.95	1.65
2-axis trough	100	235	293	414	2.95	1.25	4.15	1.75
Active linear Fresnel	111	265	347	477	3.15	1.30	4.30	1.80
1-axis trough	100	185	293	386	2.90	1.60	3.85	2.05
Covered dish	102	238	343	513	3.35	1.45	5.05	2.15
Beam splitter	177	500	939/551	1135/759	5.30/3.10	1.9 1.1	6.40 4.30	2.3 1.5

1979$; All cost data based on production rates of 10 mW per year.

38

TABLE 16. SUMMARY OF MEASURED ELECTRICAL AND THERMAL PERFORMANCE
FOR ACTIVELY COOLED PHOTOVOLTAIC CONCENTRATORS

Developer	Electrical data	Thermal data
BDM Corp	Cell string 57-in. long Cells are 2 cm x 6.5 cm. See Figure 17.	Cell temp. rise above fluid, 30°C. See Figure 18.
E-Systems	Prototype concentrator efficiency, See Figures 19 and 20 and Table 17.	Prototype concentrator efficiency, See Figure 21.
ITC	Prototype concentrator I-V curves, See Figure 22.	Not taken
GE	Prototype concentrator. See Figures 23 through 28.	See Figure 23.

Because of the early development state of various systems actual perfor-
mance data are not available for most cases. A preliminary conclusion drawn
from the foregoing survey is that E-Systems appears to be significantly
ahead of the other participants, at least in terms of having completed a
reasonable test program to date. Some of the other contractors have addi-
tional unpublished data that may be in the public domain in late 1979, so it
is premature to discount their performance potential seriously until more
data are available.

Cost Comparisons for Photovoltaic Concentrators - The PRDA-35 awards
form some basis for comparison of concentrator costs. These contracts are
being negotiated and so the cost-related details of the swards are not yet
in the public domain. Using the total amounts announced for each award, it
is clear that 1979 prices for total installed systems range from $20 to $30
per watt.

The GE study described previously estimated 1979 total installed prices
(Table 15) between $2.50 per watt and $6.40 per watt for the array concepts
they evaluated. Estimates were based on solar cell costs of $0.25 per
square centimeter and annual production levels of 10^5 square meters. Cur-
rent costs for concentrator solar cells are in the $0.75/cm^2 range and DOE
is funding several R&D efforts aimed at achieving the $0.25/cm^2 goal in
the near future.

The significance of the cell costs on the total array cost is high-
lighted by looking at the array material cost breakdown in Table 18 for the
E-Systems linear Fresnel concentrator. The bottom line projected material
cost is $160.85 per square meter of which the solar cells represent 61% of
the cost--even after using the cell cost goal of $0.25/cm^2. Fortunately
the E-Systems lens achieved concentration ratios greater than their design
goals, so they are now performing additional studies to reduce their cell
size and obviously the cost for their receiver.
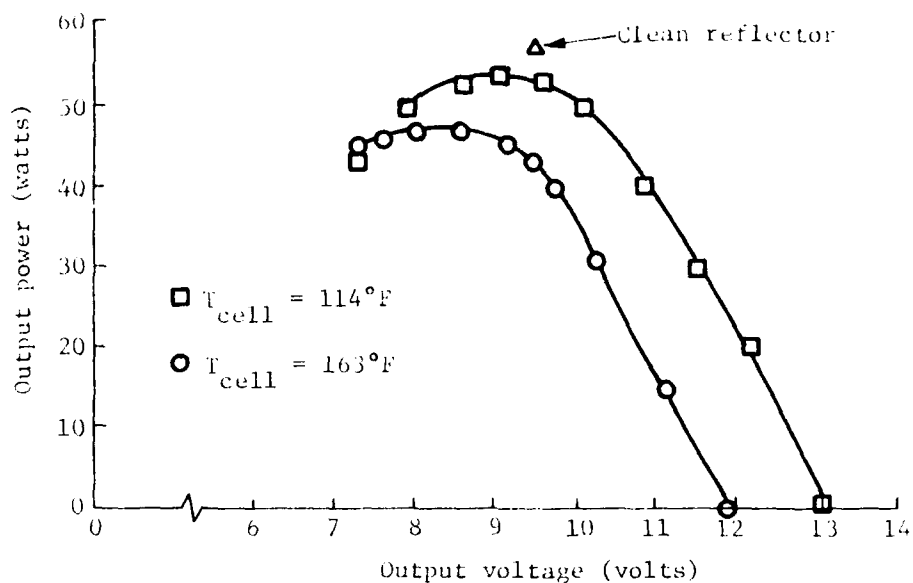
Figure 17. BDM concentrator electrical performance for one-cell string.
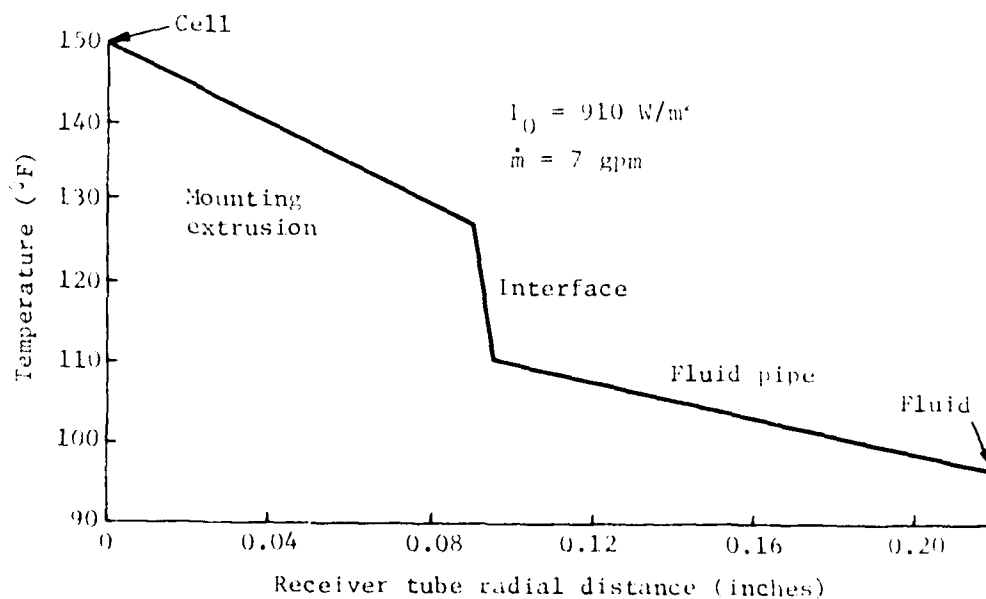
Figure 18. Cell temperature rise characteristic for BDM concentrator.

Mean fluid temperature (°F)
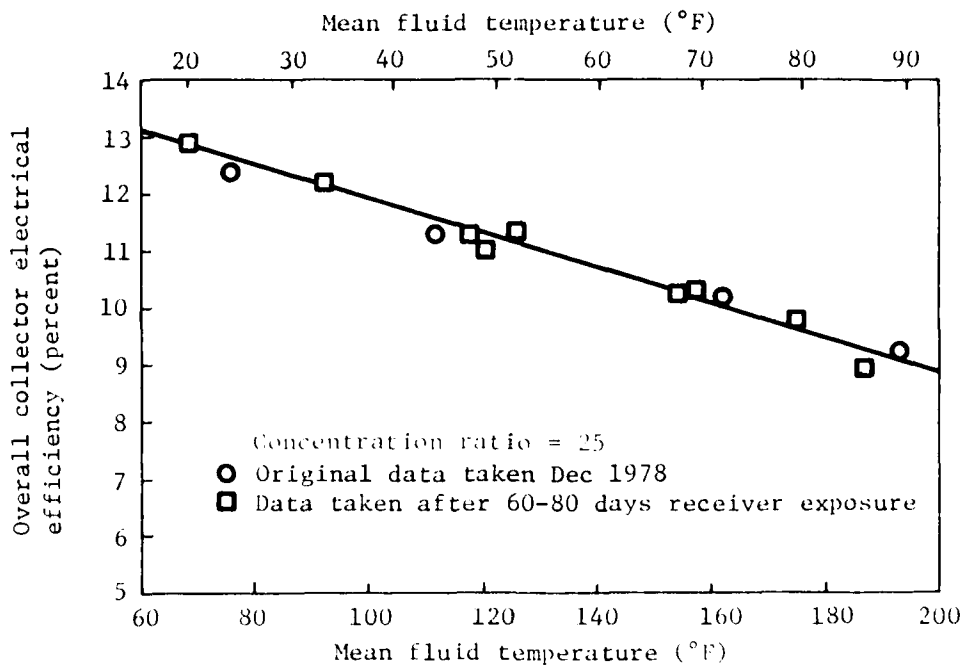
Figure 19. Electrical efficiency for E-Systems
linear Fresnel concentrator.

I_{dn} = 1003 W/m^2

T_{fluid} = 112°F (44°C)

$T_{ambient}$ = 55°F (13°C)

46 cells

$A_{aperture}$ = 1.935 m^2
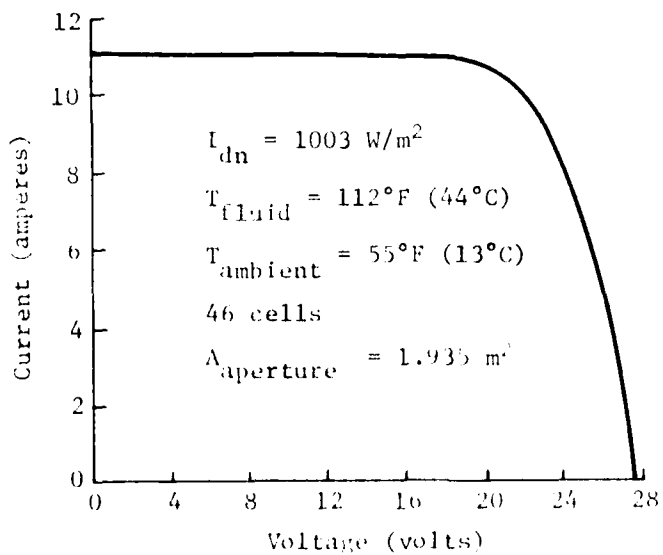
Figure 20. Measured electrical characteristic
curve for E-Systems concentrator.

41
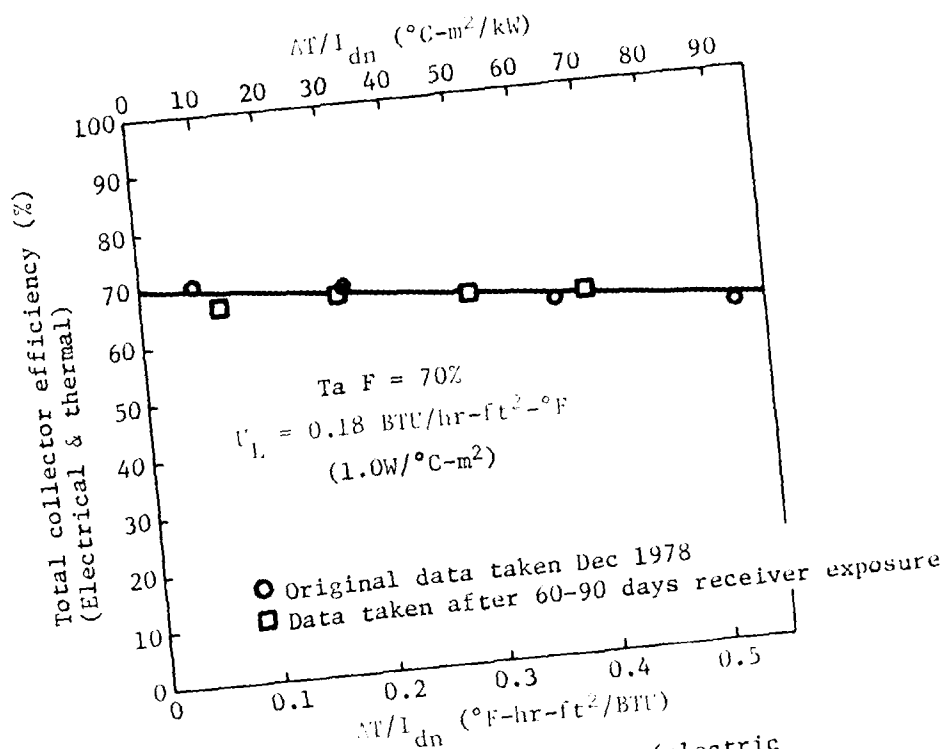
Figure 21. Total efficiency (electric and thermal) of E-Systems concentrator.
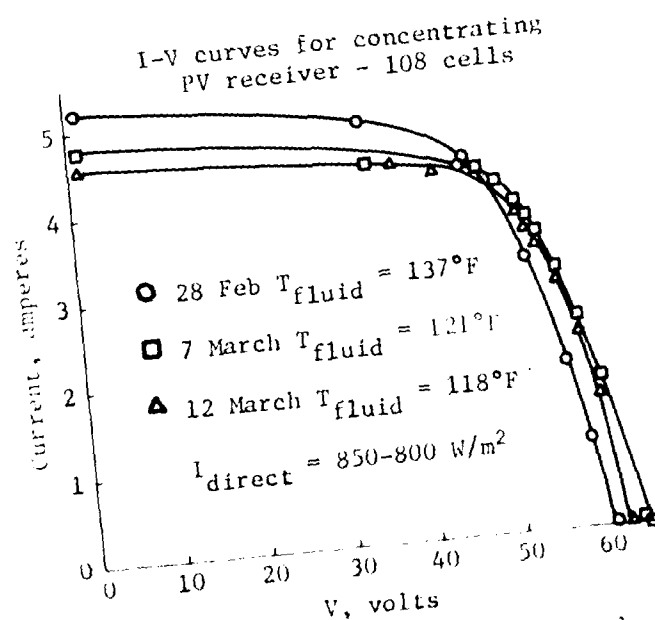
Figure 22. I-V curves for Intertechnology Corporation prototype concentrator 108-cell string.

42

Test No.	Time	Insolation (kW/m²)	PV output (watts)	PV efficiency	Overall PV efficiency* (percent)								
1	1/3/79 AM	0.849	138	5.25	5.58								
2	1/3/79 PM	0.735	90	5.04	5.46								
3	1/5/79	0.820	95	7.13	2.68								

Flow: 3.1 gpm

Aperature area (per receiver half): 1.54 m²

*Based on test insolation and cell temperature
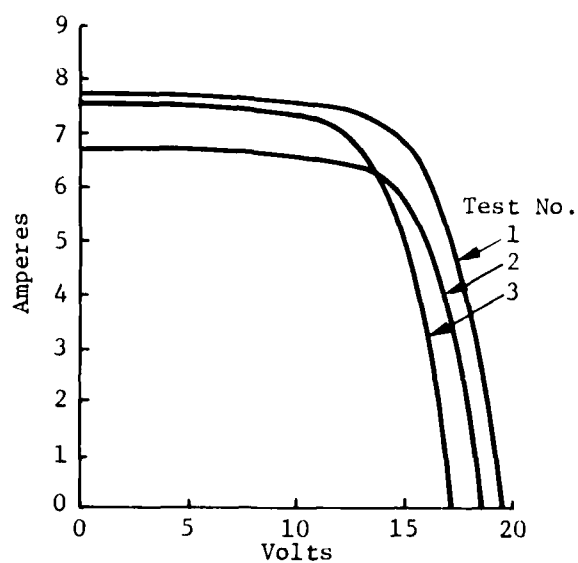
(a) Test data (transposed from X-Y plotter)
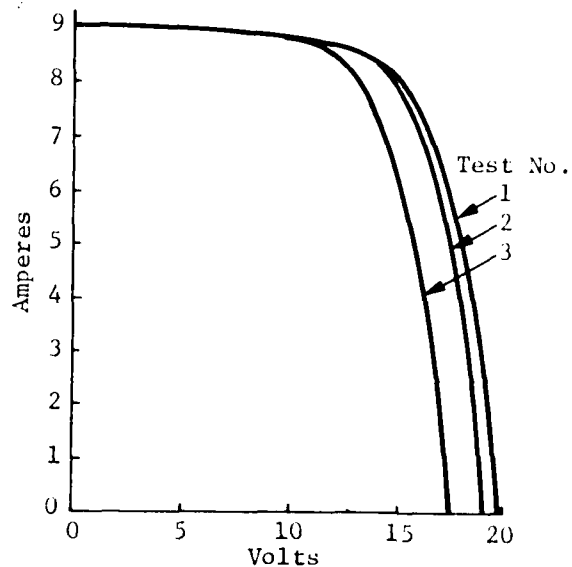
(b) Test data adjusted to 1 kW/m² insolation

Figure 23. Collector segment test results, GE concentrator.
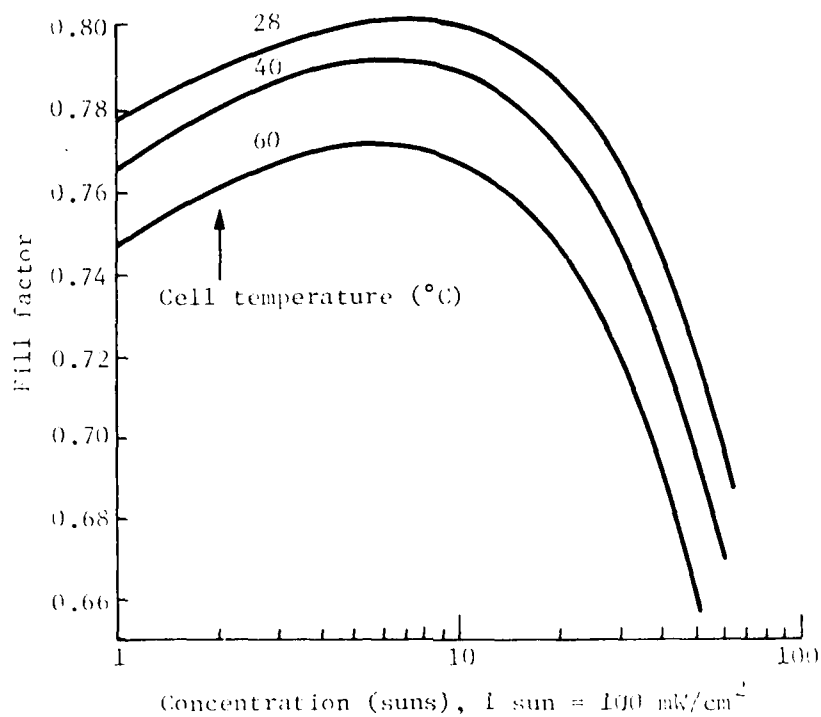
Figure 24. Fill factor vs concentration for OCLI, 3 x 4-cm concentrator cell.
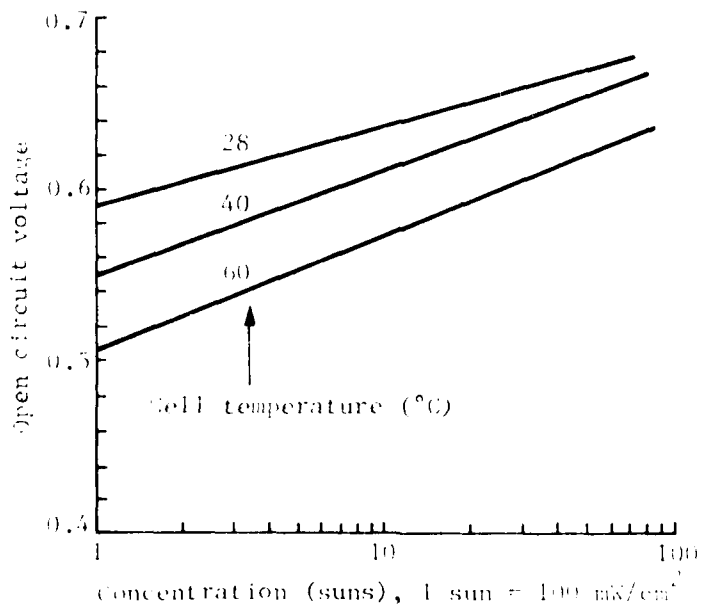
Figure 25. Open circuit voltage for OCLI, 3 x 4-cm concentrator cell

Figure 25. Efficiency vs concentration for cell 1
(3 x 4 cm to 12 cm active area) tested at 28°C.
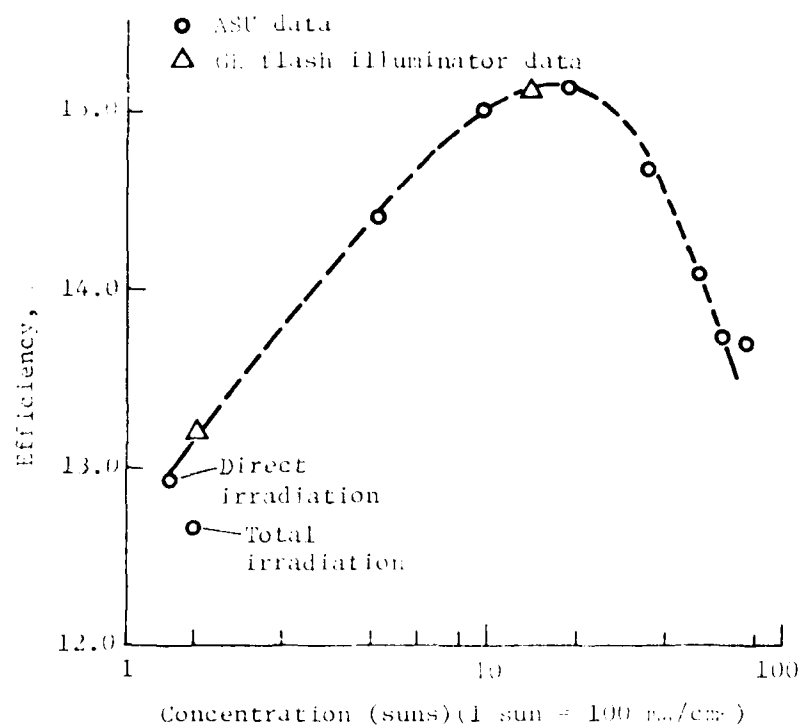
Figure 26. Efficiency vs concentration for cell,
concentration at different cell.
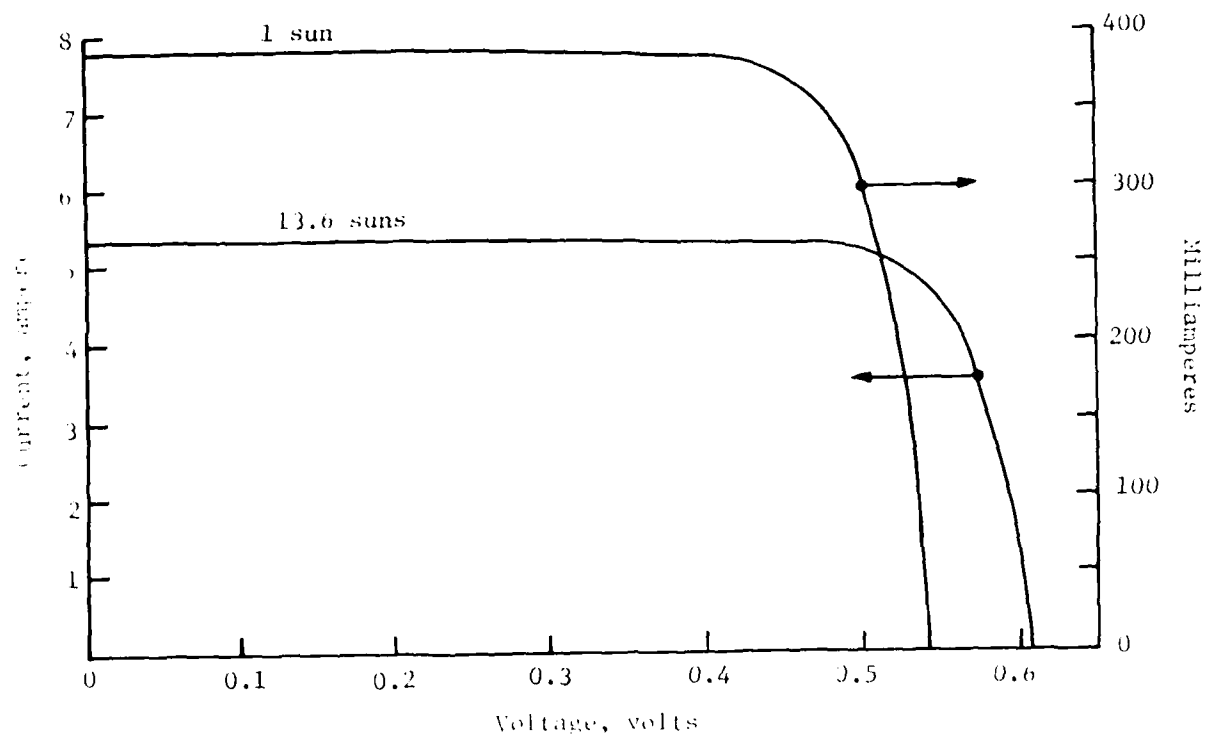
Figure 28. I-V plots at 1 and 13.6 suns for cell 008.

TABLE 17. COMPARISON OF PREDICTED VERSUS MEASURED
PERFORMANCE FOR E-SYSTEMS CONCENTRATOR

Design Conditions	Parameter	Test Conditions
946 W/m^2	Direct normal insolation	1003 W/m^2
70°F(21°C)	Ambient temperature	55°F(13°C)
114°F(46°C)	Fluid temperature	111°F(44°C)
25	Concentration ratio	25
Predicted performance (percent)	**Parameter**	**Measured Performance (percent)**
11.4	Electrical efficiency	11.3
58.6	Thermal efficiency	56.4
70.0	Total efficiency	67.7
85.0	Net lens transmittance for silicon cell response spectrum	88.7

TABLE 18. LINEAR FRESNEL ARRAY MATERIALS COST PER DOE GUIDELINES,
E-SYSTEMS 25 kW ARRAY

Component	Material	Lb/array	Matl cost ($/unit)	$/array	$/m^2
Lens	Acrylic	244.7	0.90/lb	220.23	9.88
Module housing	Steel	773.7	0.25/lb	193.43	8.67
Receiver	Copper	165.0	1.70/lb	280.50	12.58
Cells & interconnects	8,764 cm2	–	0.25/cm^2	2,191.00	98.25
Array structure	Steel	1,001.0	0.38/lb	380.38	17.06
Extrusions	Aluminum	66.8	0.85/lb	56.78	2.55
Tubing, interconnects	Copper	34.5	1.70/lb	58.65	2.63
Gear box	Steel	4.5	4.00/lb	18.00	0.81
Gears, chains	Steel	5.0	4.00/lb	20.00	0.90
Motors	–	7.5	3.00/lb	22.50	1.01
Glass	Glass	34.9	1.20/lb	41.90	1.88
Misc items	90% Steel	206.4	0.50/lb	103.20	4.63
Totals		2,544.0		3,586.57	160.85

Note: (1) Data from Reference 4
      (2) 1979 $, Assumes High Volume Production (10 MW per year)

47

TABLE 19. SOLAR ARRAY MATERIAL COST FOR ONE OF FOUR ARM

TABLE 20. CONCENTRATOR CELL TECHNOLOGY STATUS

Category	Specific designs	Concentration range	Potential efficiency[a]	Status
Silicon, single crystal	Simple p$^+$n	10-50	20%	16 to 17% in production quantities
	BSF (back surface field) p$^+$nn$^+$	50-200	21%	Lab cells at least 18
	EMVJ (etched, multiple vertical junction)	50-1000	23%	Lab cells above 20% at 600 suns
	IBC (inter-digitated back contact)	50-1000	23%	Lab cells above 18%
Nonsilicon, single junction	A·GaAs	50-2000	25%	Yielded batches above 20%. Lab cells above 23%
Multiple Junction Devices	Beam splitter	50-2000	30-35%	Lab cells tested at 28.5%
	Stacked	50-2000	30-40%	Under development

[a] At 100 mW/cm^2 and 28°C

Table 19 presents the material cost breakdown for the GE turntable-mounted linear-trough concentrator. The cell costs constitute 58% of the total material costs for the concentrator.

Concentrator Solar Cell Technology - The current thrust of the concentrator technology development program, managed by the Sandia Laboratories, is to develop high efficiency cells. This is simply because cell cost is not the significant controlling factor in concentrator arrays as in flat-plate arrays.

As shown in Table 20, the efficiency improvement results are promising. Concentrator cell efficiencies have increased dramatically in the past few years. The silicon cells are now available in production quantities with efficiencies in the 16 to 17% range at 28°C. These cells are designed to operate in 10X to 60X concentration range. The cost of such cells is now about $0.60/cm^2 for quantities of 40,000 cells.

A major improvement among the single crystal silicon device was reported by Microwave Associates. Their cells, designed to operate at very high concentration levels, have demonstrated an efficiency better than 20% at 600 suns (Fig. 29).
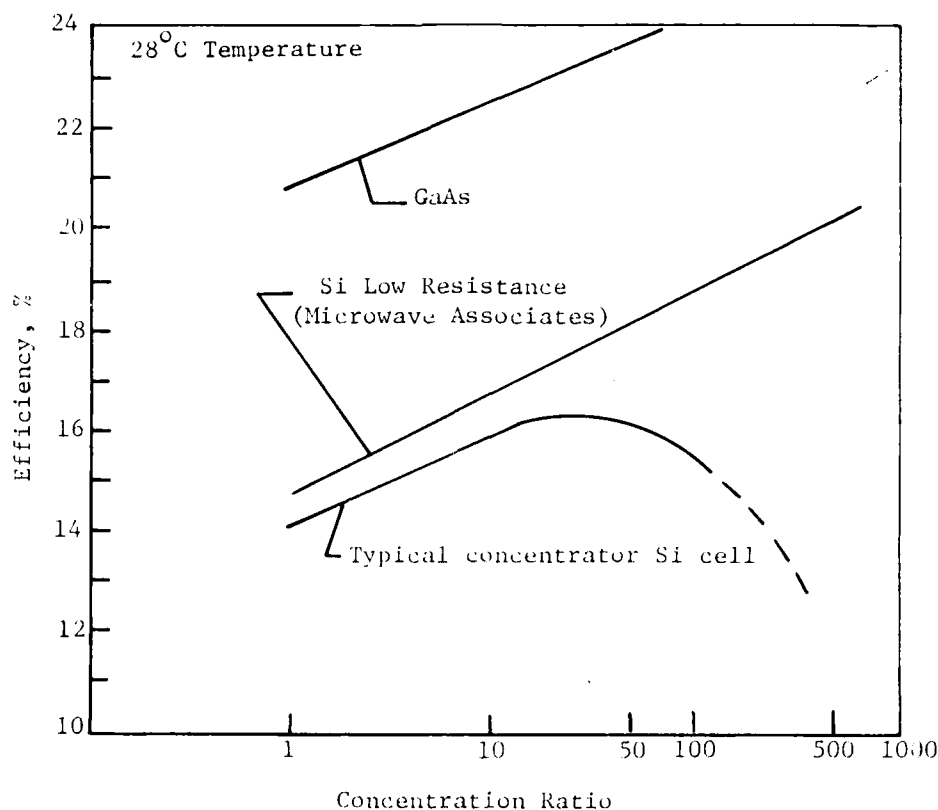
Figure 29. Efficiency vs concentration ratio for several solar cell types.

Another area of interest to the multijunction devices. Varian Associates has developed a multijunction cell design (Ref. 5) capable of 28.5% efficiency at several hundred suns. This design, illustrated in Figure 30, uses a band-rejection filter to split the beam. Energy in UV and infrared regions are transmitted to the AlGaAs (aluminum gallium arsenide) cell and the remainder to the silicon cell. The two approaches being investigated for stacked multiple junction devices are optica' stacking and actual growth of one cell on top of another.

It is apparent now that in a few years concentrator arrays can be designed with an overall efficienceis in the 16 to 22% range. The real significance of this efficiency trend can be seen when compared to the flat-plate technology. The concentrator systems have a much larger cost payoff because of demonstrated efficiency improvement potential, whereas the flat plate arrays cannot rely heavily on efficiency improvement.

5. L. W. James: Spectral Splitting Concentrator Array, Photovoltaic Concentrator Technology Development Project, SAND 79-0557, April 4-5, 1979.
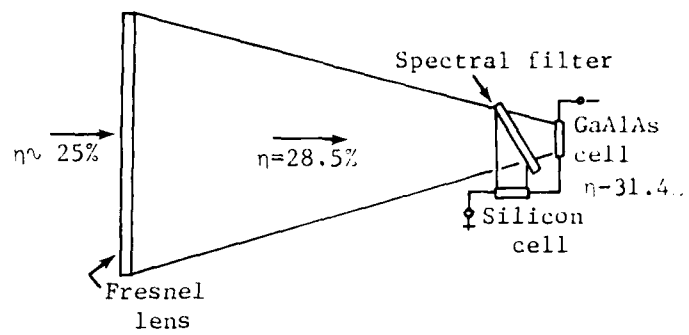
Figure 30. Multijunction concentrator assembly.

SECTION IV

PRELIMINARY DESIGN AND ANALYSIS

Power Rating Determination

In determining the power rating for an actively cooled photovoltaic power system that is best suited for the Air Force Application the following requirements, constraints, and information were considered:

(a) Electroplating facility requirements for electrical and thermal energy, including total power level (especially electrical) required as a result of demand profile shifting;

(b) Long-term insolation and weather characteristics at Tinker AFB;

(c) Short-range and long-range facility plans that would justify a certain power/energy level;

(d) Facility constraints on use of thermal energy;

(e) Design and performance data base available on preferred candidate systems;

(f) Nominal module size was to be in 15 to 50 kW range;

(g) Technology availability in 1981.

One approach is to use a conventional sizing method, i.e., determine the life-cycle costs for a range of system sizes and choose the system with the minimum life-cycle cost. This approach has flaws, however, because the high initial cost for a photovoltaic system (even using 1982 DOE cost goals) can never be recovered by displacing baseload utility power, which is available at Tinker AFB for 2.2 cents per kW-hr. Also because of the available technology options and performance data at this time, combined with constraints of the Air Force facility and the candidate systems, a detailed analysis to define an optimum power rating was considered not warranted during this study phase.

Typical plating operations at Tinker AFB require 9 vdc power at current densities ranging from 10 to 290 amps/sq ft of the plated part surface area. The Battelle study (Ref 1) estimated an average power consumption of 310 kW in electroplating operations. Using an average efficiency of 90% in the rectifiers, the maximum power level which could be fed to the plating operation is 345 kW.

The evaluation of the thermal loads in the facility (see Site Analysis covered previously in Section II) has identified two thermal loads in the South half of the facility between the chrome and nickel plating lines. These loads and their required temperature levels are:

5380 kW-hr/day at 110 to 135°F

5334 kW-hr/day at 160 to 195°F

The low-temperature load alone was considered as reasonable to supply with solar energy. The high-temperature loads could be met with larger systems (greater than 180 kW_e); however, only at the penalty of electrical output degradation due to the higher cell operating temperature.

One other thermal constraint was identified in discussions with Tinker AFB Personnel. If the plating solutions are the thermal storage element, the thermal system should not raise the solution temperature at a rate greater than 1.0 °F/hour. Rates higher than this can cause chemical instabilities in the plating solutions, which affect the quality of the plating processes.

The evaluation of facility requirements and constraints along with insolation and weather characteristics at Tinker AFB revealed that none of them construed a key driver in establishing a nominal power rating. The main criteria used in determining a power rating for a modular system were therefore based on availability and maturity of key hardware, specifically the photovoltaic system and the inverter. The modularity requirement (15 to 50 kW) and available technology options narrowed the selection simply to maximum permissable size, i.e., to 50 kW. Available inverters are in the 50 to 60 kW range (Westinghouse 62.5 kW and Delta Electronics 60 kW), and a number of photovoltaic systems could be scaled up to a range near 50 kW. The size of 55 kW_e as the photovoltaic array output at standard conditions as the power rating was based on selection of E-Systems actively cooled system.

System Selection

Electrical System Configuration – Basic objectives in the selection of an electrical subsystem are to maximize the use of existing equipment in the plating facility, use off-the-shelf power conversion equipment, provide a simple, safe, and reliable power interface with the plating facility, minimize cost of installing the power interface, and provide a system that has maximum potential for modular expansion and use at selected Air Force facilities.

Due to the size of the plating facility's electrical demand, 730 kW, compared to the anticipated maximum size of the solar electrical output, 60 kW, there is no excess solar electrical power.

An important driver in electrical subsystem configuration is the interface with the plating facility. Due to the specialized requirements of the plating tanks, 4000 amperes at up to Vdc, it is not desirable to supply dc from the solar array. Because power distribution cabling, switchgear, and user loads are presently configured for a four-wire, three-phase, 277/480 vac system in the plating shop, the simplest and most cost-effective approach is to interface with the plating facility at the 3-phase bus. The most desirable interface with the plating facility is to supply three-phase power in parallel with the utility grid at the 3-phase bus. Advantages of this interface with the plating facility are as follows:

(a)   Maximum use of existing cabling and switchgear;

(b)   Minimum disturbance to plating facility to install solar electric system;

(c)   Maximum potential for modular expansion and application at any general purpose user site served by a utility.

A three-phase interface could be installed with minimum impact on the plating facility user loads because installation of the interface would require no more down time than that required for the connection of another user load. No change in existing distribution wiring or switchgear would be required. As compared to dc ac is the dominant form of low voltage distribution. Where dc is required, rectification is supplied locally. The predominant use at other Air Force facilities are also ac; therefore, an ac interface will have the highest potential for modular expansion to other Air Force or facilities supplied by the utility.

The present disadvantage of a parallel interface with the three-phase bus is that it raises the problem of adding a nonutility-controlled source of power to the public utility grid. There is an institutional problem with the utility interface. Utilities are reluctant to allow alternative energy sources to supply power in parallel (cogeneration) for the following reasons:

(a)   Unfamiliarity with new technology;

(b)   Safety - Alternate energy source must sense loss of utility and not excite lines when the utility is down;

(c)   Quality of returned power - Harmonics must be controlled;

(d)   Rate structure - Rate adjustment for returned power has not been established;

(e)   Utility metering may not be adequate for returned power.

Five power subsystem configurations for the Tinker AFB were considered. One shown in Figure 31 uses dc-dc converters to supply dc to the plating tanks only because a dc-dc converter is not available in the plating shop that would accept a photovoltaic array input of 200-300 Vdc and provide 4000 A at 12 Vdc out. The system shown in Figure 31 is not practical. The other

four configurations are based on the cogeneration allowed by the utility and
are summarized here:

(a)   No cogeneration (2 options);

(b)   Parallel operation but no power flow to utility;

(c)   Parallel operation and power returned to the utility.

Two configurations are identified for no cogeneration (i.e., not con-
nected to the utility). In the first configuration, Figure 32, individual
loads are switched to either solar or the utility bus. In the second con-
figuration (Figure 33) an uninterruptible power supply configuration is used.

The main problems with the no-cogeneration option are the starting
transients of the lighting lamps and their steady state power factor. De-
tailed information on the inrush transients will be needed to design the
transfer of the lighting load from the utility to the inverter. The venti-
lating and tank agitation motors could also be isolated loads for the solar
array; however, their inrush transients are very severe, thus eliminating
them from further consideration.
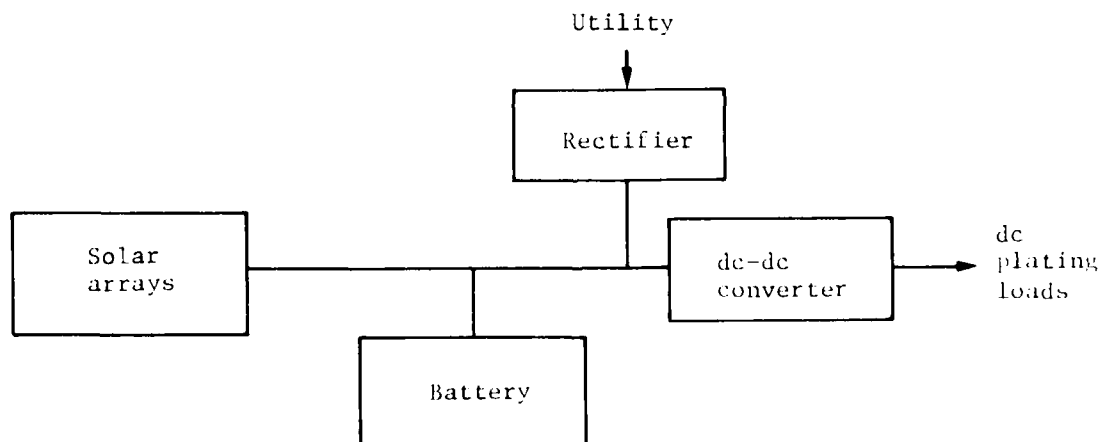
Figure 31. PVPS configuration 1

Detailed information about the steady state power factor is necessary
because of minimum power factor limitations on the inverter. It is expected
the inverter will only be specified to run for power factors in the range of
0.7 lag to 0.9 lead. It is expected the lamps will present an inductive
load. Further assessment will be required to determine if power factor
correction capacitors will be required.

In the detailed design phase, the size of the lamp banks to be switched
must be identified. For a 50 kVA inverter, it is expected there would be
five 10 kW banks, ten 5 kW banks, or a combination such as two 15 kW, two 10
kW, and two 5 kW. To switch the lights from solar to utility will require
the plating facility to add remote control switches.
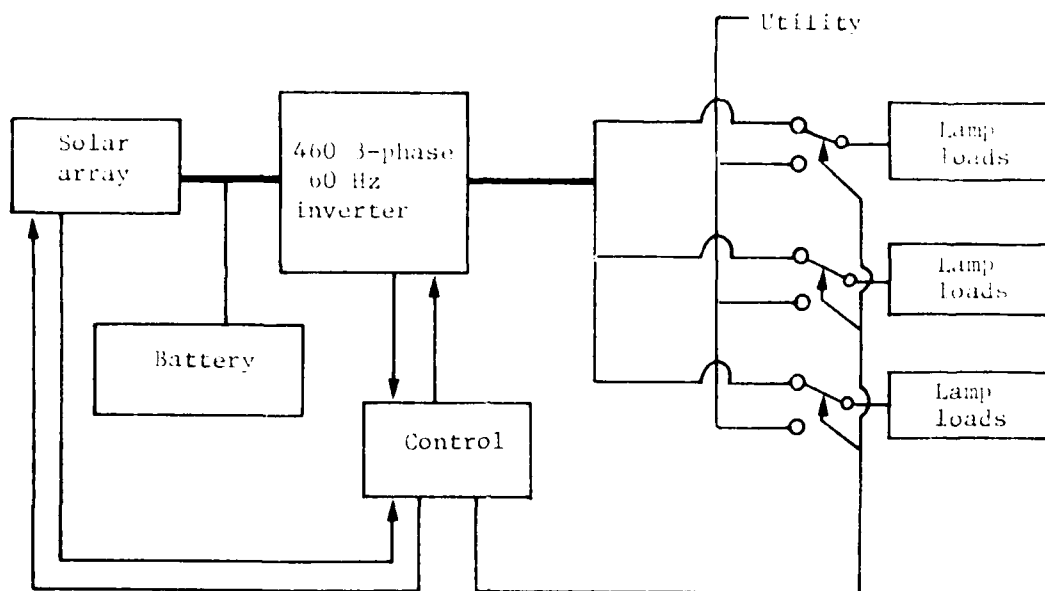
Figure 32.   PVPS configuration 2, no cogeneration with switched
separate loads.
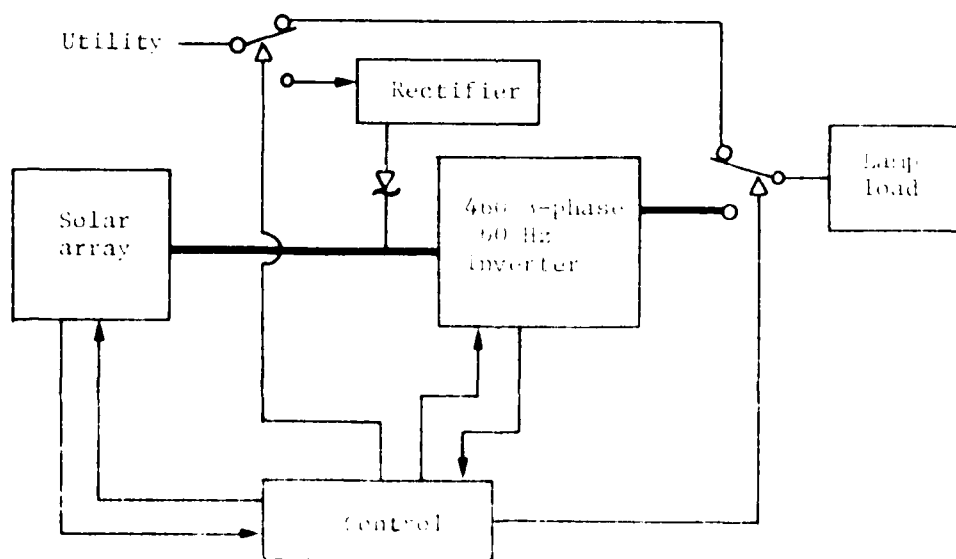
Figure 33.   PVPS configuration 3, cogeneration utility
interface through a separate rectifier.

If no cogeneration is permitted, then electrical storage in a battery will be required to prevent intermittent switching from solar power to utility power due to cloud passage. The size of the required electrical storage must be assessed if the no-cogeneration constraint is real. Also, a controller would be required to sequence the lamps between solar and utility as a function of the available solar power.

The second possible configuration for no cogeneration is shown in Figure 33. This configuration is that of an uninterrupible power supply (UPS). The utility is rectified and fed to the inverter input through a diode. Studies by Kaman Sciences have demonstrated that the array and the utility will load share (Ref 6). The disadvantage of this configuration is the loss through the rectifier. The potential advantages are smaller number of remote control switches and simplified control. The control system will sense when the system is in a loss position and turn off the rectifier and inverter and then supply the loads directly from the utility.

Figure 34 shows a configuration with cogeneration but no power flow to utility. In this configuration, it is assumed that the PVPS can supply some loads in parallel with the utility but with the requirement there be no net power returned to the utility. The PV system could supply the selected loads in parallel with the utility but it could not supply any power to any other load in the plating facility, the base, or OG&E. The utility interface will be through manual disconnect switches to permit isolation and bypass of the inverter. In this configuration, the utility and the inverter will supply the selected loads only in parallel. If the selected loads cannot absorb all the inverter output, the zero power to utility option in the inverter will prevent any power being fed to any other plating facility loads.

A system that allows the utility and solar to supply the loads in parallel and permits solar to return power to the utility is shown in Figure 35, which is same as Figure 33 functionally but with power flow to utility.

A natural system progression could be to initially install the configuration of Figure 34 with the zero power-to-utility option. After the system had accumulated sufficient operational time and data, then the decision to allow total cogeneration could be made. Implementation could be by disconnecting the zero power-to-utility option. The system would not require electrical storage because the utility is available to absorb cloud transients.

Photovoltaic Concentrator - Table 21 lists the parameters and their weighting factors used to arrive at a baseline concentrator for the Tinker AFB application. Only six candidates were evaluated in detail. Before this ranking, five systems were eliminated for various technical reasons, including:

6. D. Jarine, and R. Jones: A 64 KW Concentrating Photovoltaic Application. Kaman Sciences, DOE-CS-24278-1, Vol II, Appendix A, 1979.

(a)   Lack of technical maturity in the area of supporting structure
       and tracking systems (AAI, Kaman, Solarex, Varian);

(b)   Superiority of other similar candidates (ITC, reflecting trough);

(c)   High-cost solar cells (GaAs).

The system candidates rated in the selection process included:

(a)   Acurex Corporation - One-axis tracking parabolic trough, east-west
                             orientation;

(b)   BDM Corporation   - Polar axis tracking, linear-Fresnel trough;

(c)   General Electric   - Two-axis tracking, parabolic trough, turn-
                             table mounted;

Figure 34.   PCPS configuration 4, cogeneration with zero power to utility.
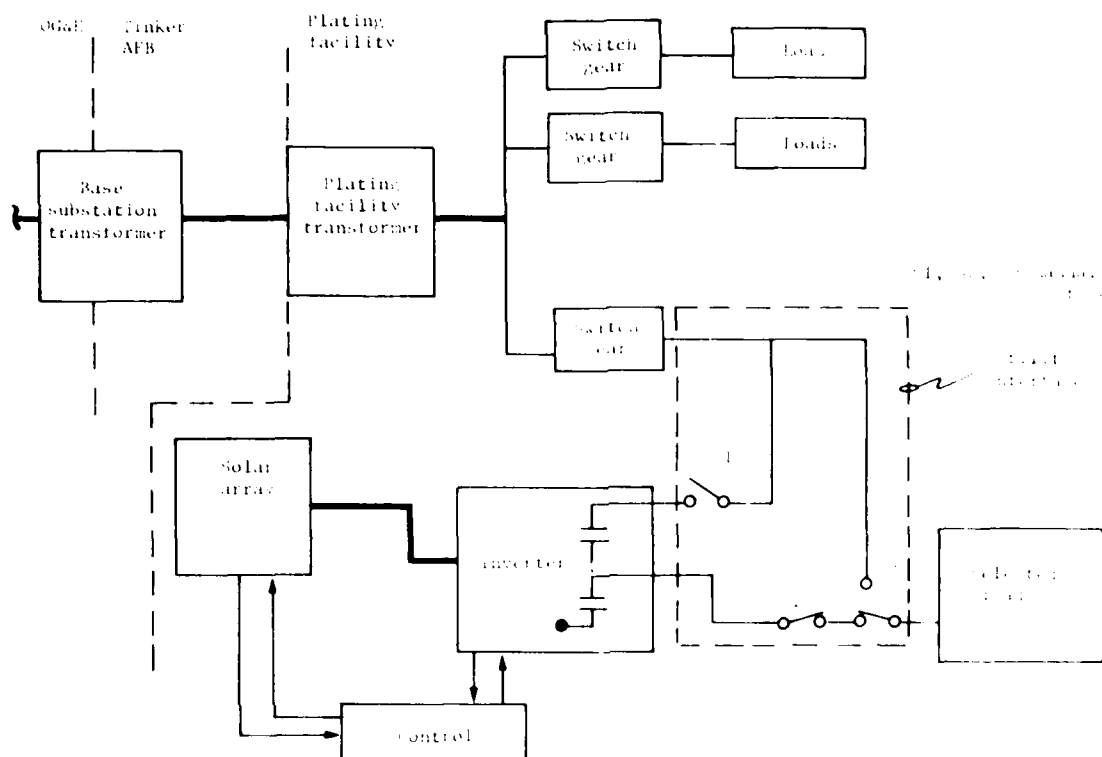
Figure 35. PVPS configuration 5, cogeneration with
power returned to utility.

TABLE 21. RANKING FOR CANDIDATE PHOTOVOLTAIC CONCENTRATORS

	Weighted score (best = lowest)					
Parameter	Acurex	BDM	E-Sys	GE	HW	Martin Marietta
Initial costs	30	30	60	6?	69	6.
Maintenance & recurring costs	20	25	20	25	20	1.
Electrical performance	60	66	30	64	42	..
Thermal performance	20	22	19	15	14	1.
Development status	45	45	30	45	50	.
Totals	175	188	159	211	195	..

(d) Honeywell   - Two-axis tracking, parabolic trough, pedestal
                             mounted;

(e) Martin Marietta   - Two-axis tracking, point-focus Fresnel, ped-
                             estal mounted.

The following discussion describes the rationale for the ranking process:

1. Initial Cost Considerations - It is difficult at this time to assess
differences in initial costs between candidate systems. Reasonable values
for total installed costs will only be achieved by competitive bids to a
common performance specification. Recent Sandia Laboratories PRDA-35 awards
provide some insight to total system costs; however, the variety of applica-
tions makes comparisons difficult. The winning contractors and normalized
total costs included:

(a) Acurex   - Hospital lighting and hot water, 85 kW $16,500/kW

(b) BDM   - Office building elec. and heating, 47 kW $23,400/kW

(c) E-Systems   - Airport utility plant, 28 kW $24,000/kW

(d) GE   - Sea World electrical and absorption cooling, 336 kW
                        $30,900/kW

Another source of cost data is the array materials cost comparison pre-
sented by M. Edenburn at the Third Project Integration Meeting in April of
1979. These data were compiled from the PRDA-35 contractors using cell as-
sembly costs of 0.10 $/cm^2 of cell area. It shows the following array
material cost and cost per unit of delivered electrical energy:

		$/m^2	$/kW-hr
(a)	Acurex	84.6	0.352
(b)	BDM	90.1	0.406
(c)	E-Systems	100.3	0.368
(d)	GE	97.5	0.365

2. Maintenance Costs - No solid data are available on maintenance
costs; therefore, all candidates are assumed to have the same maintenance
cost.

Maintenance costs include major replacement items. For reflecting sys-
tems (i.e., all except E-System and Martin Marietta) the major item of con-
cern is the quality and life of the reflector surface. Acurex uses a
Coilzak aluminum lighting sheet. This sheeting should weather reasonable
well, although industrial or seashore applications have shown up to 3% loss
in reflectivity after 3 years as reported by Alcoa.

BDM and GE use metallized films for their reflectors. These films are susceptible to damage from windblown particles and improper handling. Also, these films are difficult to clean without degrading the surface reflectance. Until additional life test data are available, applications specifying metallized film should still be considered experimental.

E-Systems and Martin Marietta use Fresnel lenses, which use Acrylic material. This approach is expected to provide a minimum of a 20-year life.

3. Electrical Output Comparisons - The rankings for electrical performance are based largely on the work of M. Edenburn at Sandia Laboratories. He compared the various systems (except Honeywell) with computer simulations and estimated the following component efficiencies:

		Optical	Target	Cell	Tracking
(a)	Acurex	0.89	0.89	0.138	0.84
(b)	BDM	0.81	0.98	0.138	0.84
(c)	E-Systems	0.85	0.92	0.138	0.96
(d)	GE	0.82	0.90	0.138	1.00

The product of the optical, target, cell and tracking efficiencies yields the net system efficiency. The tracking efficiency determines available energy. One-axis troughs intercept significantly less energy than 2-axis or polar.

Long-term degradation in electrical output will be largely due to loss of reflectivity in troughs (see above). The Fresnel lens approach provides excellent weather protection for the Martin Marietta and E-Systems designs. The Honeywell reflector uses the sagged-glass mirror concept, which should have excellent weather characteristics.

4. Thermal Output - All comments about thermal are identical to the preceding comments on electrical. Only E-Systems has reported good measured thermal data.

5. Development Status - Three factors were considered in this area, including (1) availability of test data, (2) performance history on similar contracts and (3) the potential for near-term improvements in cost and performance.

The availability of reported test data has been a key problem in the selection process. Only E-Systems has supplied the authors with test results. BDM did report some test data; however, they showed a 30% gap from the coolant fluid to cell. BDM also reported electrical output of 3 watts versus a projected 7 watts for their test string of cells, although the projected value was based on a larger cell area and larger collector aperture.

Performance history is about equal for Acurex, BDM (Solar Kinetics), GE, and Honeywell. All have solid background in large solar thermal systems including:

(a) Acurex
- DOE/New Mexico Solar Irrigation Experiment, Willard, NM, 625 m^2
- Campbell Soup - process heat, Sacramento, CA, 360 m^2
- Solar Power Plant, Spain, 500 m^2

(b) BDM/Solar Kinetics
- Solar Irrigation, NM, 650 m^2

(c) E-Systems
- Prototype fixed-mirror distributed focus concentrator for DOE and 11-m parabolic dishes for JPL

(d) GE
- Knitwear Factory, parabolic dish, Shenandoah, GA

(e) Honeywell
- Mississippi College
- Honeywell Bldg, Minneapolis, 1900 m^2

(f) Martin Marietta
- Heliostat field for Sandia Test Facility

The potential for cost and performance improvements among the candidate arrays has been the subject of GE's ongoing study, which assessed the impact of technology improvements on reducing $/peak watt costs. Their preliminary results show that high-concentration Fresnel systems (400X) and medium concentration circular Fresnels (100X) have the greatest potential for cost-effective improvements. Linear-Fresnel systems of the E-Systems type also show good potential.

6. __Array Field Location Considerations__ - The preliminary evaluation of the Building 3001 roof loading capabilities indicated the following:

(a) General Electric turntable troughs could possibly be located over the high bay roof area between columns X and Y; however, a complete structural analysis and review of the porposed system would be required. This location is about 300 feet east of the plating shop roof.

(b) The Martin Marietta and Honeywell pedestal mount systems could be installed over the low bay roof area that is adjacent to the plating shop on its east side. The pedestals must be mounted directly over the existing building columns which must be extended to reach the actual roof level.

(c) The E-Systems, BDM, and Acurex concentrators could also be located on the low bay roof; however, Tinker AFB personnel believed that they should be installed in line with the roof columns, which are on 60-foot centers in the north-south direction. This

constraint would result in a very inefficient packing density because normal spacing would be as low as 18 feet for the E-Systems array. For large systems this would be an unacceptable constraint because it would require excessive field wiring and piping to interconnect the arrays.

Power Conditioning - From the Site Description Section, Electrical Loads, it is clear that power in the plating facility is distributed by a four-wire, 3-phase, 60 Hz, 277/480 volt bus system. The plating tank automatic converters produce 4000 ADC at up to 12 Vdc from a 3-phase, 277/480 volt input. These automatic converters are specialized equipment for operation in proximity to the corrosive environment of the plating tanks. The plating facility does not have dc-dc converters capable of operating from the solar dc bus and supplying dc to the tanks (they do not exist off the shelf anywhere else).

The unregulated dc voltage from the solar array bus cannot be used directly by any existing user loads identified in the plating facility. To be able to supply electrical power to the existing 3-phase loads in the plating facility, it will be necessary to add power conditioning equipment between the solar dc bus and the 3-phase distribution bus. This power conditioning equipment will consist of a four-wire, 3-phase, 277/480 volt inverter powered from the solar dc bus.

Some factors of importance in selecting an inverter for a photovoltaic application will now be considered. The output voltage is compatible with expected 200-300 Vdc solar bus.

1. Parallel Operation with Utility - Line commutated appears to be cheaper and has a lower parts count, but has the significant drawback of high (greater than 10%) total harmonic distortion; in the current waveform, current harmonics are undesirable for user loads. Depending on the utility, such harmonics may or may not be allowed in power returned to the utility. A line-commutated inverter generally can only operate when the utility is present. The self-commutated inverter is somewhat more expensive than a line-commutated inverter; but, the self-commutated inverters are able to achieve much lower THD in the current waveform (less than 1% at any harmonic). To be able to deliver utility quality power, it appears that a self-commutated inverter should be chosen from those presently available.

2. Isolation Transformer - There should be transformer isolation between the utility and the solar dc bus to ensure that a semiconductor failure will not result in dc appearing on the utility ac bus.

3. Loss of Utility Detector, Shutdown, and Restart - This is of extreme importance because of safety requirements for linemen. When the utility goes down, the solar inverter must detect it and shutdown; otherwise, the inverter could energize lines thought to be dead by the utility lineman. The restart strategy after the utility returns can be either manual or automatic.

4. _Inverter Survey_ - Potential suppliers of inverters for this solar photovoltaic application were surveyed and the results summarized in Table 22. Two vendors, Westinghouse and Abacus Controls, are under contract to Sandia Laboratories for inverter development for solar photovoltaic applications. PRDA-35 Project information was used as a guide to potential suppliers. Telephone contacts with the inverter vendors were made, product information sheets obtained, and a meeting held with one vendor.

Windworks and Delta seem the most mature because they provide off the shelf hardware. The Windworks unit is line commutated and not suitable for a stand alone application. Also, the high harmonic distortion may be a severe drawback for a system returning power to the utility. The Delta unit will be used in the Acurex Phase 2 PRDA-35 for a hospital with electrical and hot water loads at Kauai, Hawaii. The Delta unit appears to be technically acceptable for this application, but it does not appear to be the most cost effective. Abaccus is under contract to Sandia to develop a 10 kW solar photovoltaic inverter. They have developed and tested a single phase unit for parallel utility operation. For this application, they proposed using three, single-phase units with added controls to provide a three-phase unit. Westinghouse is also under contract to Sandia Laboratories for the develo]ment of a 50 kW, three-phase inverter for solar photovoltaic applications. They have a prototype and have accumulated 300 hours of parallel utility operation. From a review of the Westinghouse inverter, specifications, plans, development, and price, it was concluded that the Westinghouse inverter is directly applicable with little or no modification and was therefore selected for the baseline electrical system.

Thermal System Configuration - Two thermal distribution systems were considered, including:

(a)   Conventional solar water heating using a water tank for thermal storage,

(b)   Direct tank heating, which uses the mass of the plating solutions for thermal storage.

The conventional system with a storage tank is shown in Figure 36. For a nominal 50 kW system size, 16,000 gallons of storage is required. The advantage of this system is its ability to store a large quantity of excess thermal energy for use later in the evening; however, for the Tinker AFB application there are several disadvantages of this approach such as the following:

(a)   Higher array field temperatures are required to store the energy at an average temperature level greater than the plating tank temperatures

(b)   Thermal losses through the storage tank insulation can be significant

TABLE 22. CHARACTERISTICS OF SEVERAL THREE-PHASE INVERTERS

Vendor:					
	Windworks (Hans Meyer)	Delta (Leonard Hodges)	Abacus (Peter Zicmpel I)	Westinghouse (Daniel Farren)	Reva (Kenneth Moviton)
Rating	40 kVA	50 kVA	30 kVA	50 kVA	50 kVA
Design status	Off shelf	Off shelf	Assemble single units to make 3	Developed for Sandia 300 or Parallel w/ utility	Off shelf except must add parallel feline capability
Price (k$)	17	65	30	35	25
$/kVA	425	1300	1000	700	500
Commutation	Line	Self	Self	Self	Self
Input V range (Vdc)		180-290	200-300	200-500	
Parallel with Utility	X	X	X	X	Must be developed
Isolation transformer	External	X	X	X	X
Loss of utility detector & shutdown	Inherent	X	X	X	Must be developed
THD in current	12	3	3		
Auto peak pwr trk		X	X	X	Must be developed

*Total Harmonic Distortion

(c)   Installed cost for storage can be expensive. Typical installed costs for conventional water storage tanks in DOE's Solar Demonstration Program ranged from $1.00/gallon for interior (inside a building) steel tanks to $3.70/gallon for buried steel tanks (Ref 7).

The preferred thermal subsystem is the second option shown in Figure 37. The solar energy is distributed directly to the plating tanks whenever the array field coolant temperature is above the delivery set point. Advantages to this approach include:

(a)   Simplicity, minimum number of components,

(b)   Minimal thermal losses,

(c)   Low cost.

The main disadvantage of this system is the limited thermal capacity available due to the requirement that the plating temperatures be kept in a $20^\circ F$ band and also the constraint that the rate of plating solution temperature changes be less than $1^\circ F$/hour. Assuming that all the low temperature tanks are used, their storage capacity is 69,000 gallons. We can investigate this approach with a simple clear-day analysis:

On a clear day in the summer, the incident solar energy could be as high as 10 kW-hr/m^2. For a 50 kW$_e$ system (assume 500 m^2) at 50% thermal efficiency the thermal output would be 2500 kW-hr on that clear day. If this energy is collected over a 6-hour period, the load at the tanks would be 5380 x (6/24) = 1345 kW-hr so the remaining 1155 kW-hr must be stored in the plating solutions. For 69,000 gallons of solution, the resulting temperature rise would be:

$$T_{rise} = 1155 \times 3413/(69,000 \times 8.33)$$

$$T_{rise} = 6.8^\circ F$$

or about $1.1^\circ F$/hour temperature rise, which is slightly above the $1.0^\circ F$/hour solution temperature rise rate constraint specified by Tinker AFB plating personnel.

7. T. A. Kins, and R. Kirkpatrick: Cost Data Collection from Solar Demonstration Projects. Proceedings of Operational Results for Solar heating and Cooling Systems Conference, SERI/TP-49-063, Colorado Springs, Colorado, November 1978.
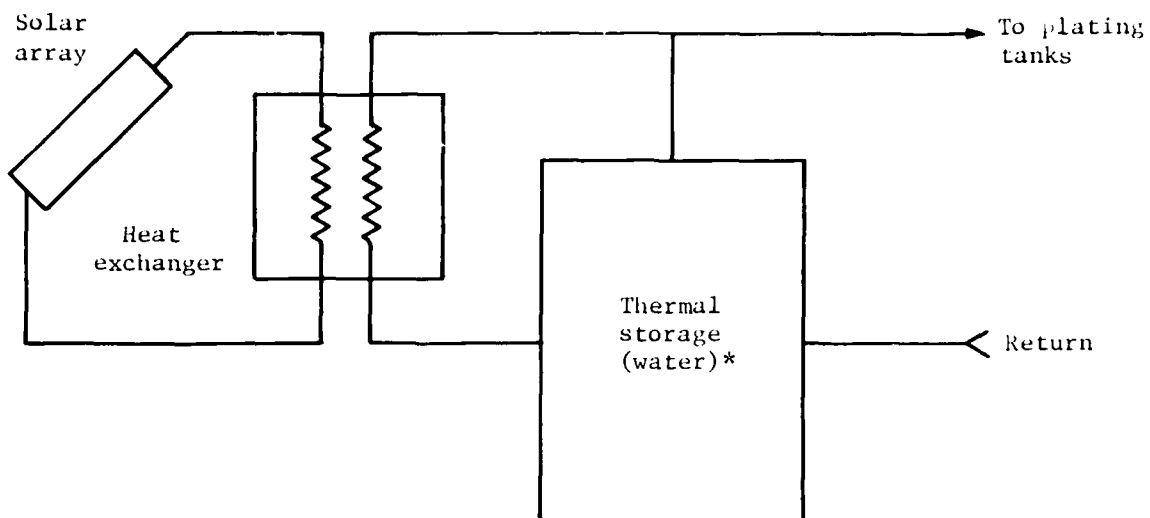
*Storage volume typically 1.5 to 3 gal/ft^2 of aperture

Figure 36. Conventional solar thermal system with storage.
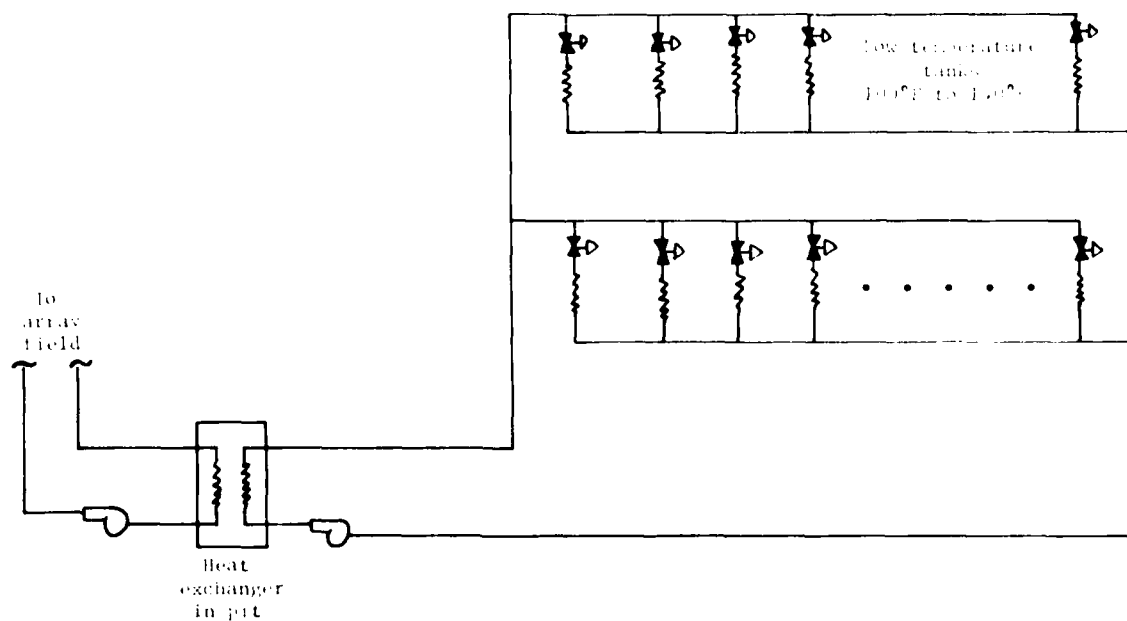
Figure 37. Piping schematic for electroplating facility.

System Design

Baseline System Configuration - The baseline system we have selected for the Tinker AFB electroplating facility application is illustrated in Figure 38. Key features include:

(a)   System sized to deliver 50 kW electrical power and 260 kW thermal power;

(b)   E-System's linear-Fresnel concentrator with polar axis tracking;

(c)   Power conditioning designed to operate in parallel with utility;

(d)   Thermal subsystem to provide solar energy to low-temperature plating tanks.

This thermal subsystems is included as an option although a general recommendation for the baseline configuration is an all-electric system. Details of our preliminary design for the electrical and thermal subsystems are covered in this section. Figure 39 shows the block diagram for the baseline photovoltaic power system.

Electrical Subsystem - The following subsystems are included in the electrical system:

(a)   Inverter

(b)   Utility Interface

(c)   Control

(d)   Instrumentation and Data recording

(e)   Emergency power supply

(f)   Lightning protection

The baseline system shown in Figure 40 assumes that cogeneration with power returned to the utility (other plating shop users or other base users) will be permitted.

Inverter - The Westinghouse 3-phase, 50 kVA inverter developed for Sandia Laboratories is the recommended power converter. A summary of the Westinghouse inverter specifications is given in Table 23.

Utility Interface - The utility interface will be at the four-wire, 3-phase, 270/480-volt bus. A first cut at this interface is shown in Figure 40. This interface cannot be defined fully at the present, but only after base and OG&E requirements are incorporated. See the Systems Integration section, for a more detailed discussion about the requirements and plans for defining the utility interface in detail.
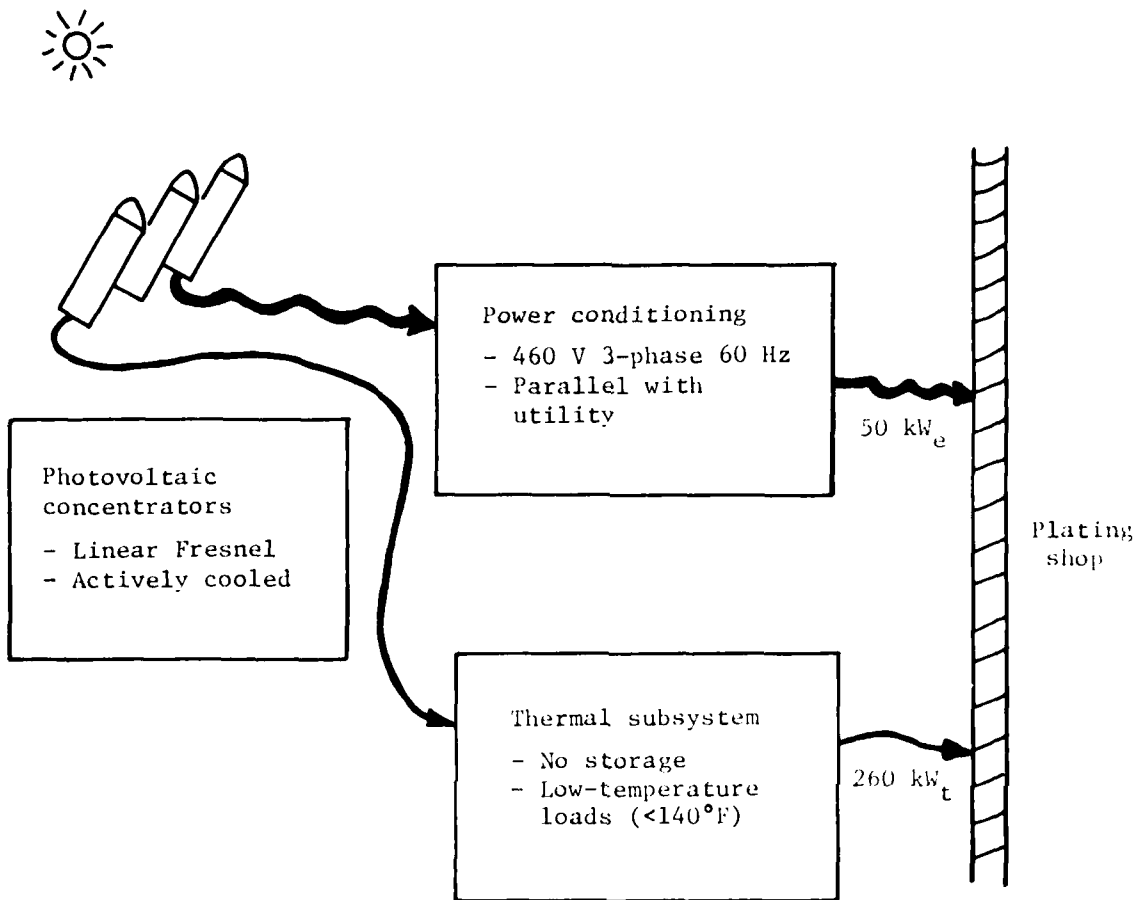
Figure 38. Baseline photovoltaic system for Tinker AFB.

Array System Control and Tracking Subsystem - The PV array system control includes the start up, sun tracking, shut down, and fault conditions that are incorporated in the control circuitry. The tracking system is designed to provide roll axis tracking accuracy of ± 0.05 degrees; tilt axis accuracy of ± 0.75 degrees; and automated controls to allow automatic roll axis tracking and safe operation.

Roll axis control is self-starting, active tracking, and responsive to insolation intensity and fault conditions. Tilt axis tracking requires periodic manual adjustments simultaneously positioning all 22 arrays to compensate for the declination angle variation, which occurs over a 6-month period. Figure 41 illustrates the roll and tilt block diagrams for the E-Systems tracking scheme (Ref 8).

8. M. O'Neill: A Fresnel/Photovoltaic Concentrator Application Experiment for the Dallas-Fort Worth Airport. Phase I - System Design, Final Technical Report, DOE/CD/95311-1, March 1979.
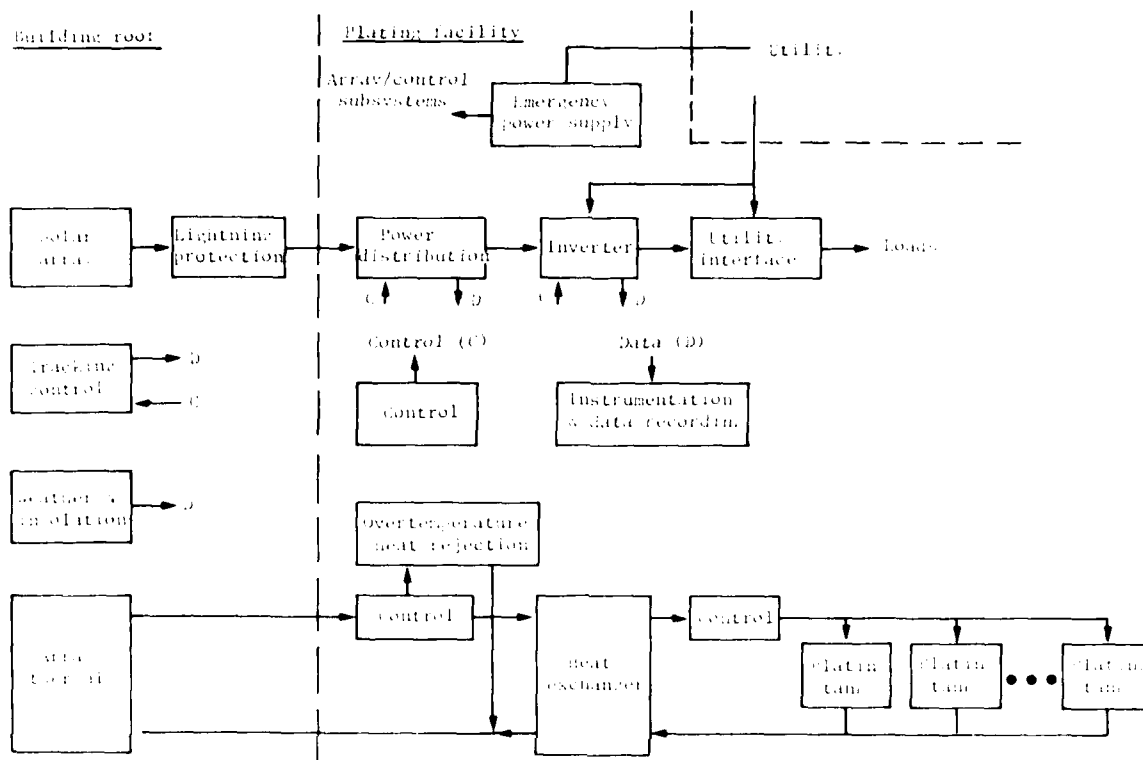
Figure 39. Baseline photovoltaic power system block diagram.

Roll axis tracking control is provided by the tracking and control unit, which is mounted on the master module of each array. The tracking and control unit provides:

(a)   Automatic start of array track;

(b)   One direction track;

(c)   Bi-directional slew;

(d)   Roll axis tracking error signal;

(e)   Low insolation level detector and track inhibit;

(f)   Insufficient insolation and return to stow signal;

(g)   End-of-day return to stow signal;

(h)   High-temperature limit return to stow;

(i)   Loss of pump motor return to stow;

(j)   Reset tracking logic at stow in preparation for the next day.

Roll axis tracking is single-direction track and two-direction slew. The unit will initiate tracking and follow the sun until the end of day occurs and a stow command is generated. Intermittent cloud cover will cause the insolation level detector to generate a track inhibit command when the low insolation threshold is violated. The arrays will stop tracking until the cloud passes and the arrays restart and slew to the sun's new position.

A wind sensor mounted with the weather station provides a contact closure with a wind speed exceeding 45 mph (20 m/s). This switch action will activate the tilt axis drive motor to move the arrays to the tilt axis stow.

Inverter Control - The Westinghouse inverter has a microprocessor - based autonomous controller. No intervention or stimulus from an outside controller is necessary for the inverter to: (1) automatically start when sufficient solar array power is available; (2) connect the inverter to the utility; (3) disconnect from the utility when sufficient solar array power is unavailable or the utility is lost; peak power track; and provide automatic shutdown when safety limits are exceeded.
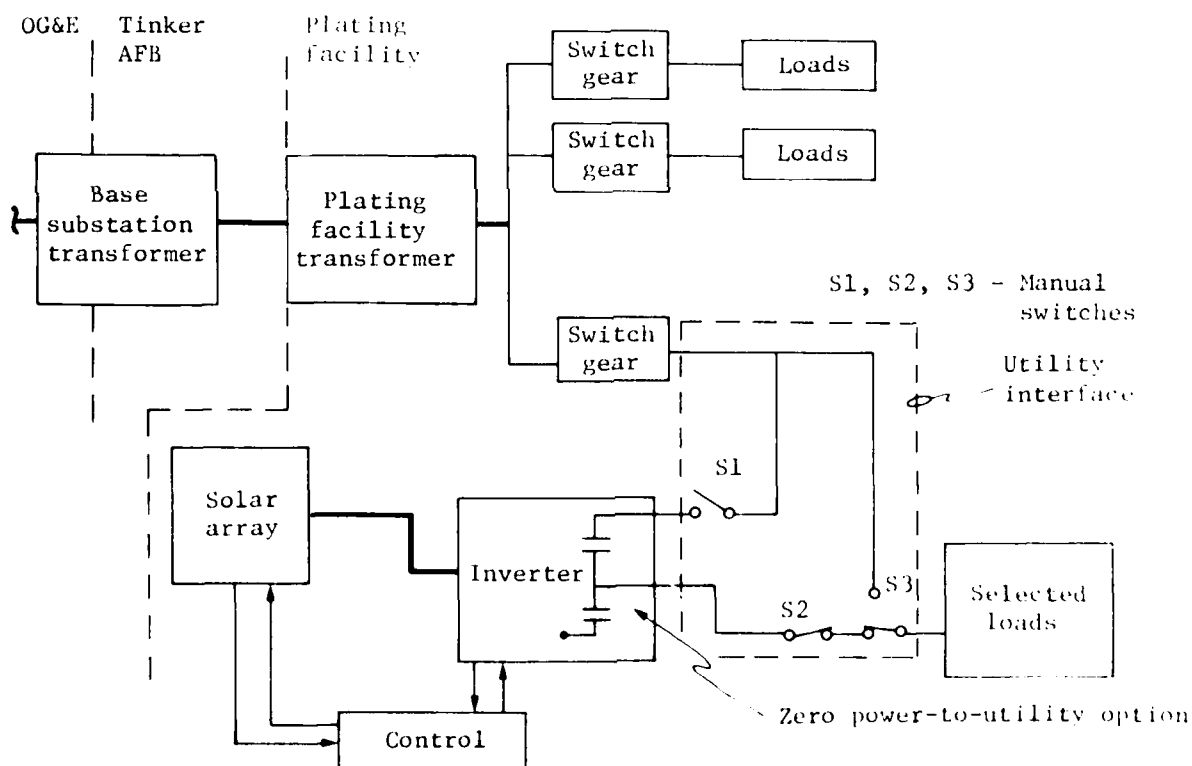
Figure 40. Simplified functional schematic of electrical system

TABLE 23.   INVERTER SPECIFICATIONS

Parameter	Requirements
Input voltage	200 to 300 Vdc
Output voltage	270/480 Vac, 3-phse, 60 Hz
Output power rating	50 kW
Overload rating	150%, 1 minute 125%, 5 minutes
Output current limiting	Each phase
Efficiency	83% Minimum at 25% of full load 90% Minimum at rated load
Unbalanced load	One phase limited to 1/3 of rated load
Power factor (PF)	Rated power over 0.9 lead to 0.7 lagging PF
Output frequency	Synchronous to utility Free-running capability, 58 to 62 Hz
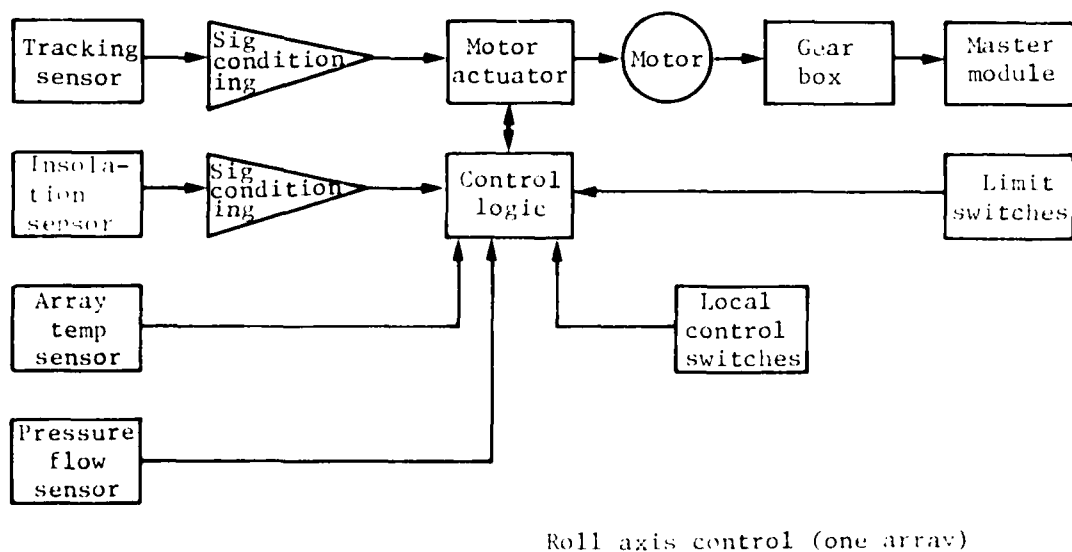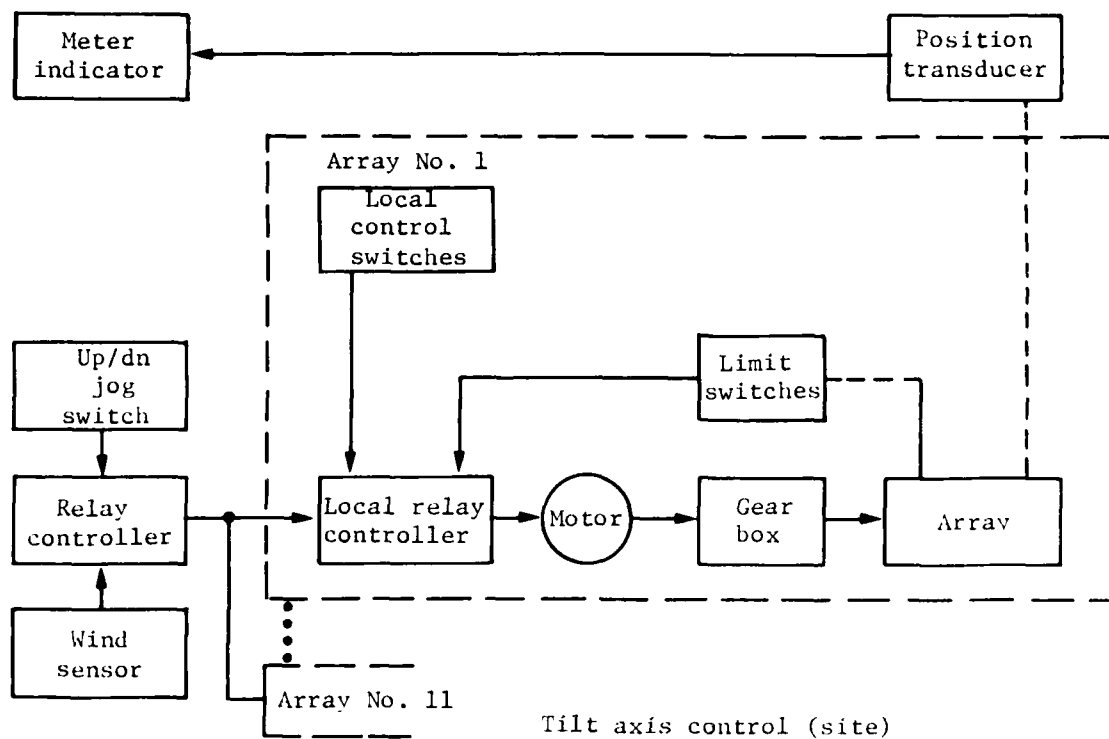
Figure 41. E-Systems concentrator array control system.

Instrumentation and Data Recording - Because the system is for prototype demonstration purposes, sufficient instrumentation and data recording are identified. Table 24 lists the measurements required along with typical sample rates and recording rates.

Data acquisition and recording can be accomplished by a data logger like the Doric Scientific. The data logger is the simplest and cheapest method of acquiring the data, but the process monitor has the added capability of performing limit checks. The advantage of the process monitor is that its limit checking capability could be used to back up the autonomous safety shutdown systems in the array field and inverter. The disadvantage is an increased cost over a data logger. A hard copy and video display can be used with either the data logger or process monitor to obtain real-time data. The Westinghouse inverter has a display panel for inverter parameters.

Array Mechanical Subsystem - The photovoltaic array is composed of twenty-two array assemblies built by E-Systems, Inc, of Dallas. Each array consists of 10 collector modules mounted in a structural steel frame as shown in Figures 42 and 43. In each array the modules are interconnected in series, both electrically and thermally, to produce 2.5 kW_e of dc power and 13 kW_t of thermal power. The twenty-two arrays are interconnected in parallel to provide 55 kW_e of dc power at 260 volts, nominal, to the power conditioning equipment for conversion to useable ac. The thermal system for the arrays is also connected in parallel to provide about 260 kW_t of thermal power to the plating tanks in the Electroplating Facility.

In Table 25, the key elements of the major components of the E-Systems are described. Figure 44 shows the details of the collector assembly.

Thermal Distribution Subsystem - The thermal distribution subsystem is a simple recirculation loop through which a 30% ethylene glycol/water solution circulates, absorbing thermal energy in the collector field, transferring the energy collected through a plating shop heat exchanger, and then returning the fluid to the collector field. The thermal collection and distribution system is shown in Figure 45. The heat exchanger module, which includes the pump, heat exchanger, expansion tank, controls, and instrumentation, will be located on the floor of the plating shop.

An over-temperature heat rejection unit will be located on the low bay roof near the array field. This unit is sized to reject the total thermal output of the array and will be used only when the plating tank thermal distribution system is inoperative in a failure mode of down for maintenance reasons.

Figure 46 shows the thermal distribution piping to the low temperature plating tanks in the south half of the shop. This piping will be located under the tanks in the pit area. Figure 47 shows the typical piping detail at a plating tank that has a nominal temperature requirement of 120 to 140°F. Whenever the main solar distribution system is active, the control valve will be open to allow flow to the plate heat exchanger in the tank. By resetting the existing steam valves to the low end of the temperature range, the solar system will be able to provide energy to the tank whenever the solar supply water is greater than approximately 135°F.

TABLE 24. MEASUREMENT CHARACTERISTICS

Measurement	Number	Sample rate (minute)	Record rate (per hour or daily)
Array mechanical			
Fluid temperatures	10	5	5
Fluid flow	2	5	5
Array electrical			
Subarray voltage	22	2	3
Subarray current	22	2	3
- Field energy	1	1	Daily
- Field power	1	2	3
Module voltages		2	3
Cell voltages		2	3
Cell temperatures		2	3
Power conditioning			
Inverter input dc voltage	1	5	3
Inverter input dc current	1	2	3
Temperatures	8	2	3
⊘ Current	3	5	3
⊘ Voltage	3	2	3
⊘ Power (real)	3	5	3
⊘ Power (reactive)	3	5	3
Frequency	3	2	3
Input power	1	5	3
Input energy	1	1	Daily
Output energy	3	1	Daily
Control			
Array status	8	5	2
Inverter status	10	5	2
Utility status	3	5	2
Switch positions	15	5	2
Emergency power system			
Status	1	5	2
Output voltage	1	5	2
Output current	1	5	2

The plate heat exchangers used in the plating solutions are a vendor-supplied item (Dean Products). Cost for these heat exchangers is significant (on the order of $1,400 each) due to the requirement for either stainless steel or titanium to withstand the corrosive plating solutions.

TABLE 24. MEASUREMENT CHARACTERISTICS (CONCL.)

Measurement	Number	Sample rate (minute)	Record rate (per hour)
Insolation & weather			
Direct normal insolation	1	2	3
Total tracking insolation	1	2	3
Wind speed	1	2	3
Wind direction	1	5	3
Barometric pressure	1	5	3
Ambient air temperature	1	5	3
Precipitation	1	5	3
Date & time	Each Record	Each Record	Each Record

System Integration

Requirements and Constraints - The significant requirements and constraints have been identified for a photovoltaic application at the Tinker AFB electroplating facility and are summarized in Table 26. The key requirement is for 100% backup of electrical and thermal power to meet the critical mission of the plating facility. Maximum service life of 25 years should be a design goal for all photovoltaic systems being developed today because this will increase their economic practicality on a life-cycle cost basis.

Utility Interface - The focal point of integrating the PVPS with the plating facility is the utility interface. By interfacing the solar inverter at the 460 Vac/3-phase/60 Hz bus, the simplest, most cost effective interface will be achieved. This interface will have minimum impact on the plating facility.

The baseline approach to the utility interface was shown previously in Figure 34. It is expected this interface will be at a four-wire, 480/3-phase/60-Hz bus in the plating facility. The inverter will have transformer isolation between its dc input and ac output so there will be no chance of an electronic failure allowing dc to appear on the ac bus.

At a minimum, manual safety switches for isolating and bypassing the solar inverter are anticipated. The utility interface can only be defined and documented with the active participation of the base power distribution office and Oklahoma Gas and Electric Company. If any further action is taken at Tinker AFB both the base power distribution personnel and OG&E should be made team members from the beginning. The importance of this
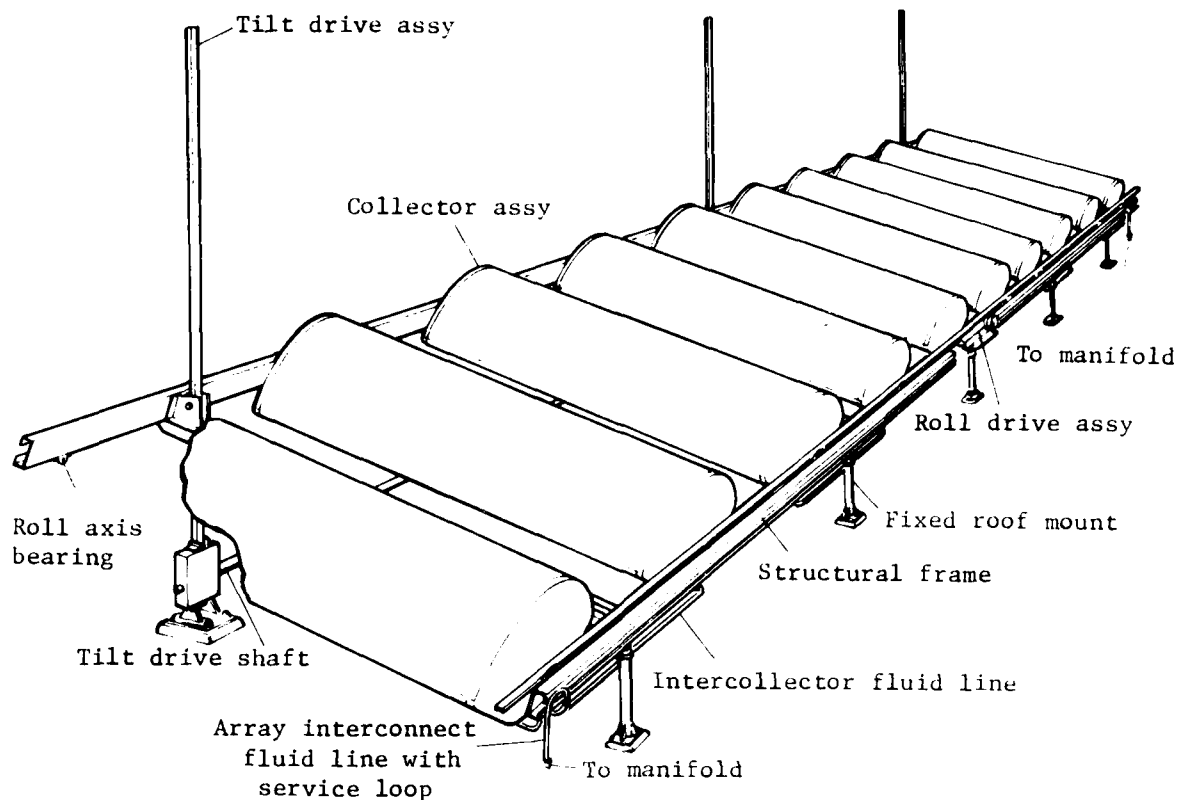
Figure 42. Photovoltaic concentrator assembly, E-Systems.

"institutional" interface cannot be overemphasized because either the base or OG&E could prohibit a photovoltaics application from generating power in parallel with the existing system.

Performance Summary for Baseline 50 W System

Figure 48 summarizes the performance of the 50 kW system. Based on the total solar energy available (1057 MW-hr/year) at Tinker AFB, the total utility capacity and natural gas displaced were determined to be 80,600 kW-hr/year and 2.4 million cubic feet/year, respectively. Figure 49 shows the I-V curve of one module measured by E-Systems at 100 W/cm^2 insolation.

The annual performance of the thermal subsystem was computed with the SOLCOST solar energy design program (Ref 9). The SOLCOST thermal analysis algorithm performs one average day simulation for each month of the year and takes into account the following factors:

(a)   The solar collector is modeled with an efficiency curve shown in Figure 50.

(b)   The average day simulation is driven by a synthetic direct normal solar radiation model based on site dependent clearness numbers.

(c)   Thermal storage effects, including time dependent thermal load delivery.

(d)   Piping and storage tank insulation losses.

Details of the SOLCOST thermal analysis method are presented in Appendix B.

Significant output from the analysis was that the net solar energy delivered to the plating tanks amounts to 1158 kW-hr/day or 21.4% of the 5380 kW-hr daily load. This converts to an annual displacement of 2,404,000 cubic feet of natural gas for a cost savings of $4640 at 1979 gas rates.

Figure 51 shows the projected thermal performance is essentially linear as a function of system size.

The E-Systems concentrator is an excellent thermal collector; however, the piping losses and heat exchangers degrade the total system performance significantly. Figure 52 shows the E-Systems energy balance on their con-
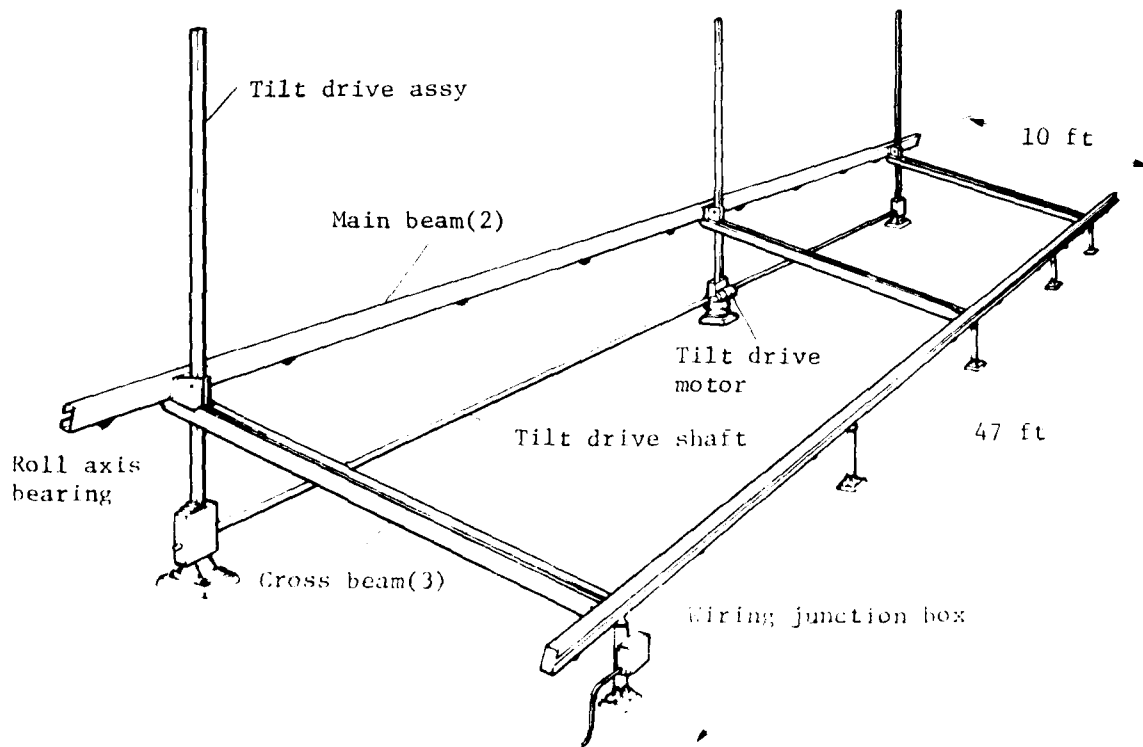
TABLE 25. PHOTOVOLTAIC OS TYPE ARRAY SPECIFICATION

Component	Description	Wt (lb) per array assy
Collector module		
Housing structure	10 modules per array	1275
	Galvanized sheet steel construction	
	Integral roll axis shaft or axial cg	
	Roll axis drive sheave integral with end plate	
	Environmental lens & joint seals	
Lens	3-mm thk curved acrylic for whole aperture	
Receiver assy	53 silicon solar cells mounted in series on copper heatsink	
	Copper heatsink braised to a 15-mm dia copper tube	
	Polyurethane insulation between receiver and housing	
	Supported along full length of housing	
Drives		356
Roll axis drive	5 watt, ac-pulse drive	
	Single linear actuator per array	
	Closed loop active tracking in single direction	
	150° sky coverage	
	Slew speed - 5°/min	
Tilt-axis drive	50 watt, ac drive	
	Three linear actuators driven by common shaft	
	Manual jog control for periodic adjustment	
	Remote tilt position indication	
	Slew speed - 1 3/4°/min	
Array structure		883
	High stiffness/weight ratio sheet steel frame	
	Approx 14.6 m x 3.0 m	
	Tilt axis at south face	
Interfaces		25
	Self aligning bearings for module/frame mount	
	Ten modules wired in series to provide 260 Vdc output	
	Ten modules plumbed in series for coolant fluid flow	

Total array weight 2544 lb
Weight/aperture 10.6 lb/ft·

79
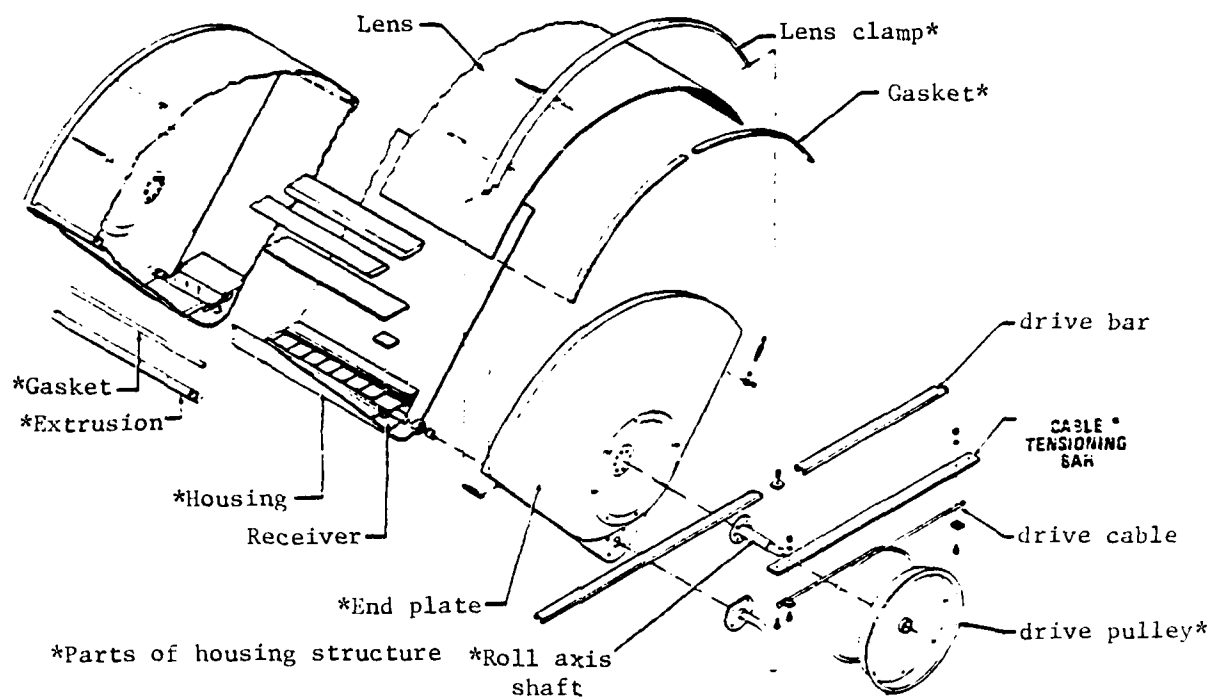
Figure 44. Collector assembly.

*Parts of housing structure
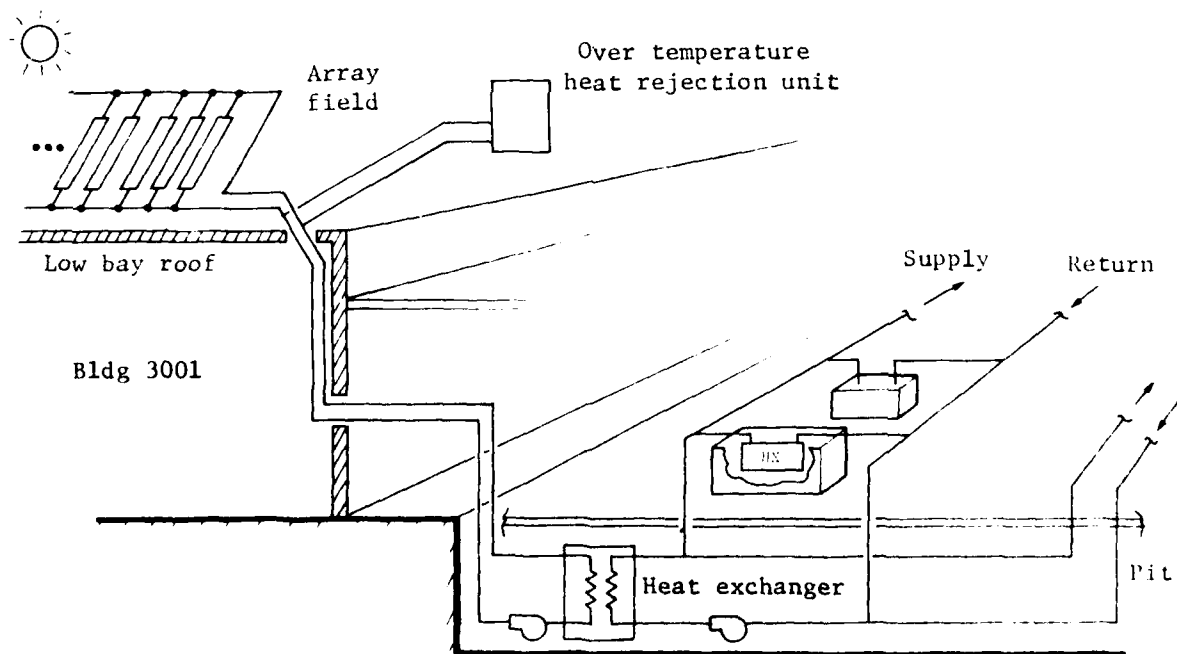
Figure 45. Baseline thermal system for Tinker AFB electroplating facility.

centrator at PRDA-35 design conditions. The Tinker AFB appliction requires
higher cell operation temperatures (i.e., 75ºC vs 55ºC design point for
E-Systems) in order to provide useful heat to the plating tanks, thus re-
sulting in increased losses from the solar collector and piping systems, and
reduced electrical output due to the higher operating temperature (by a fac-
tor of -0.5% per ºC).
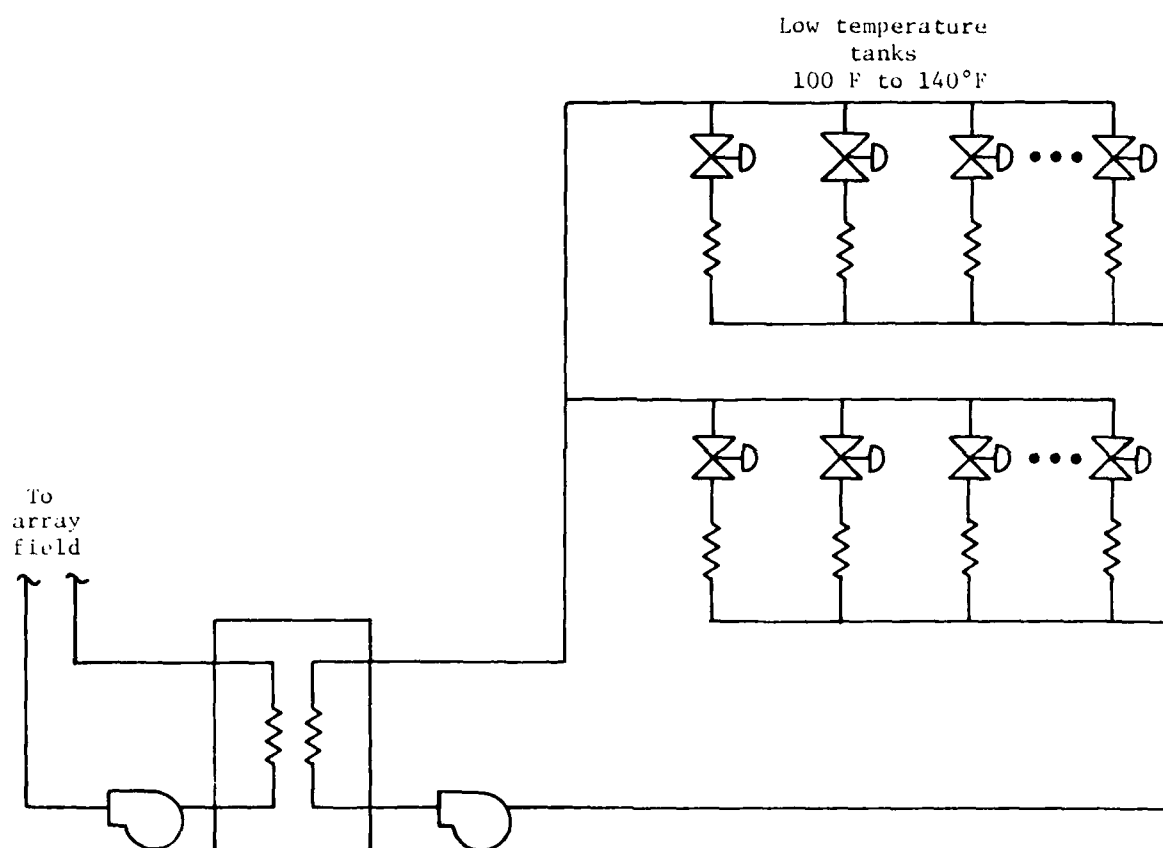
Figure 46. Thermal distribution subsystem.

9. R. Giellis, D. Hull: SOLCOST-A Solar Energy Design Program. Proceedings
    of Systems Simulation and Economic Analysis Conference, January 23-25.
    1980 San Diego, CA. SERI/TP-351-431 (Solar Energy Research Institute,
    Golden, Colorado).

130°F normally open
140°F (close at 140°F

Solar supply 150°F

Return

120 to 140°F required

Heat exchanger plate

Existing steam system
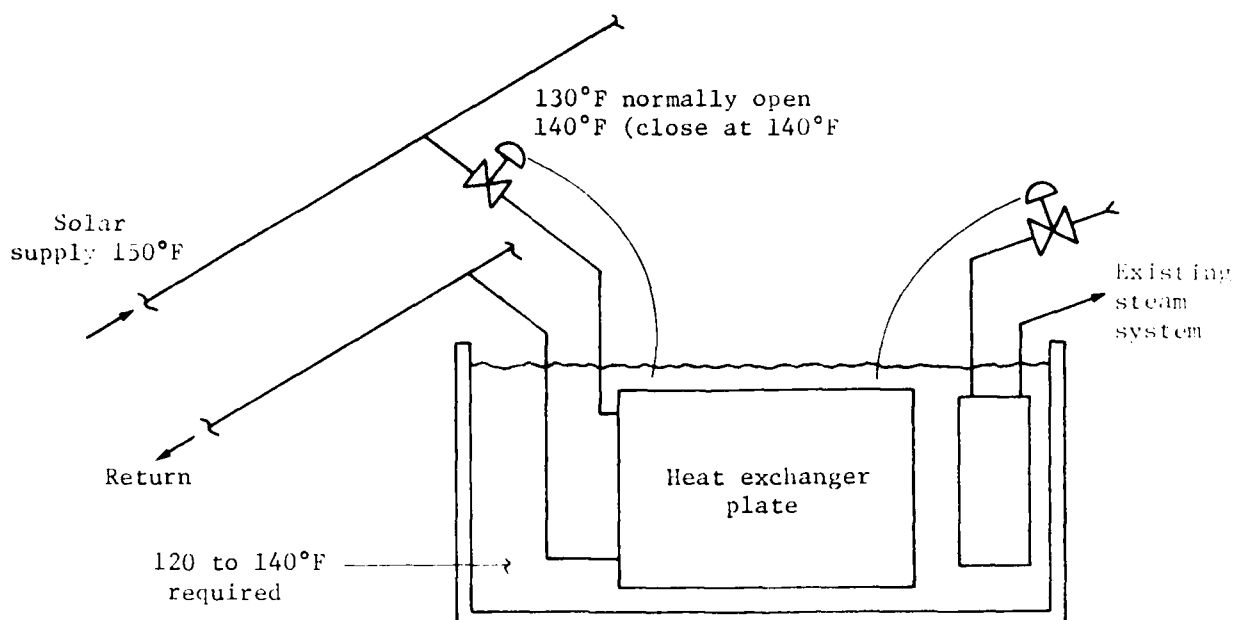
Figure 47. Piping details at plating tank.

TABLE 26. BASIC INTEGRATION REQUIREMENTS AND OS TYPE CONSTRAINTS

	Requirements	Constraints
General	100% conventional backup for thermal and electrical subsystem	– Roof-mounted troughs must be on column lines (i.e., 60-ft center. .
	20-year system life	– PV site to be as close as possible to plating facility.
	Minimum maintenance	– Minimize shadowing of PV array surface.
Electrical	Provide adequate power quality at utility interface	– Use of existing converters – Meet utility safety requirements
Thermal and structural	Maintain plating solution Temperatures within $^{+}_{-}$7.5° or $^{+}_{-}$10°F of set point	Plating solution temperature changes must be less than 1°F/hr.
	Overtemperature protection for PV arrays/	
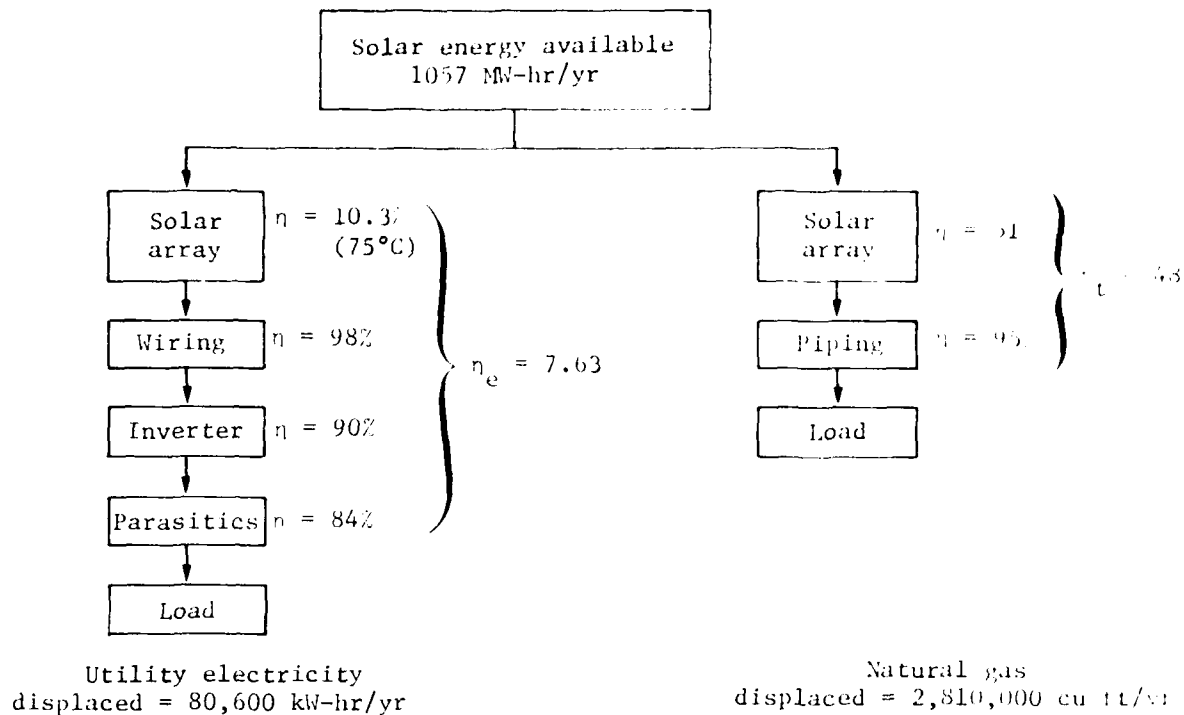
Figure 48. Performance summary for 50-kW system.
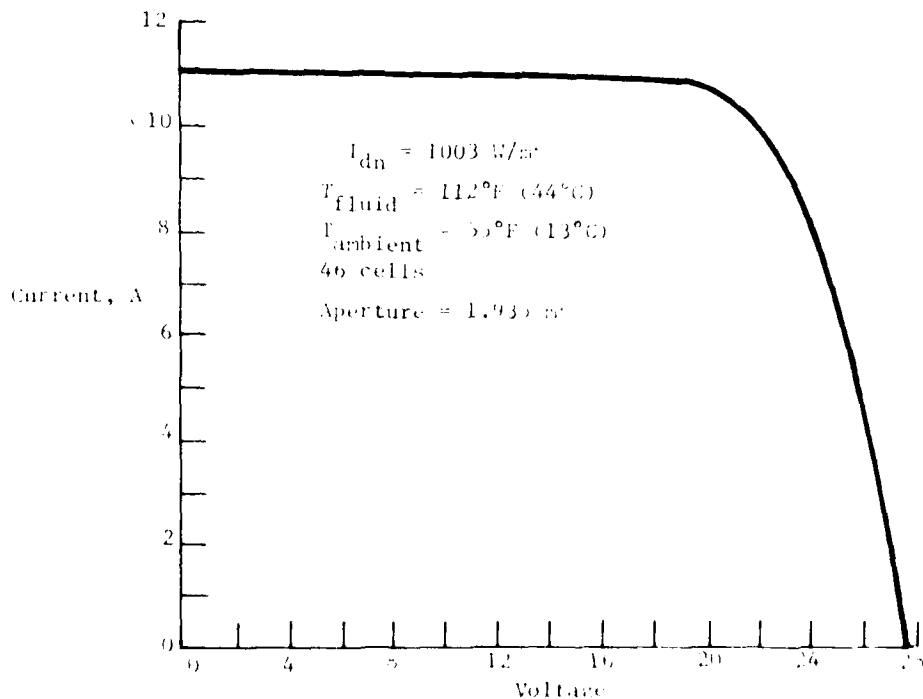
Figure 49. Measured module performance characteristic curve for E-System concentrator.

Figure 50. Thermal efficiency for a-System concentrator.

Legend:

T_i = Collector inlet temperature, °F

T_a = Ambient air temperature, °F

I_{DN} = Direct normal irradiance, Btu/hr-ft²

Note: The slope and intercept of this efficiency curve have been derated to account for the heat exchanger in the thermal delivery system.
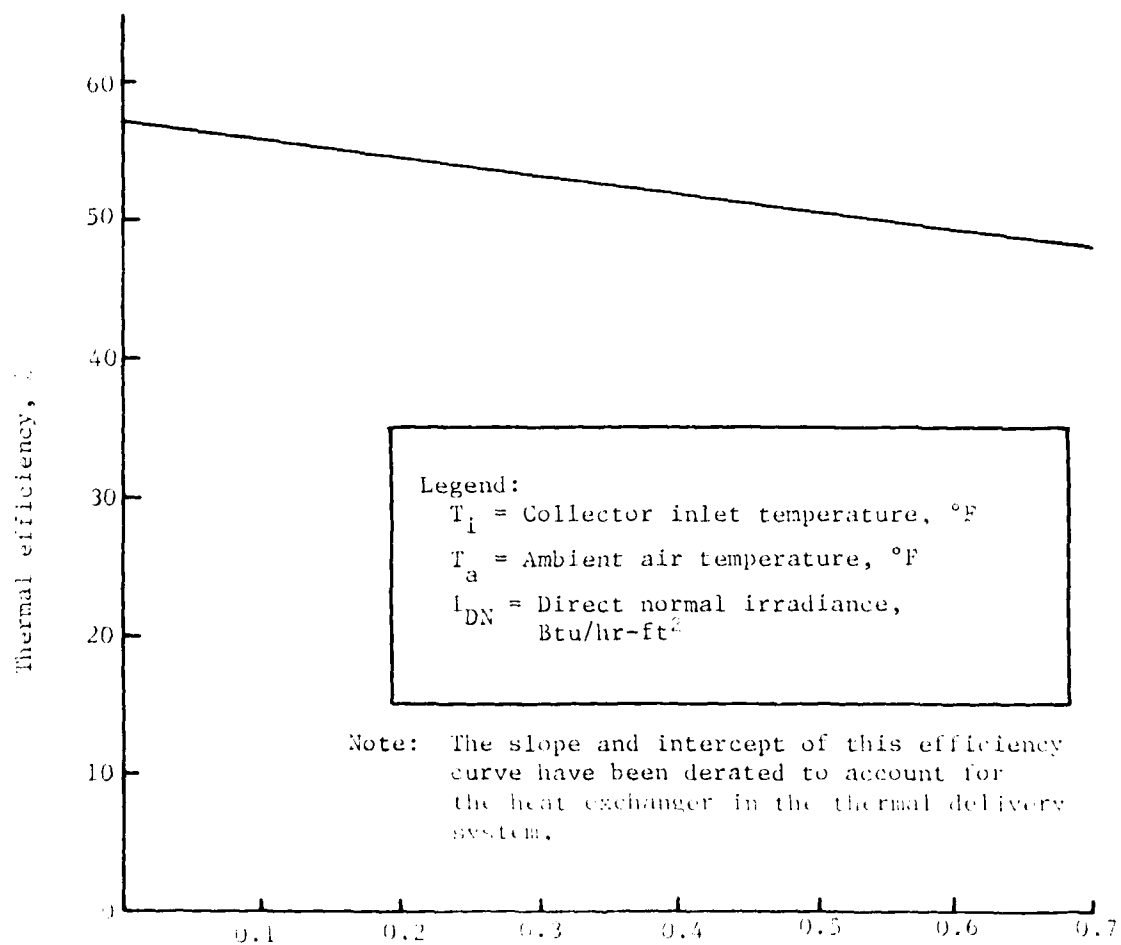
$(T_i - T_a)/I_{DN}$, °F/Btu - hr - ft²
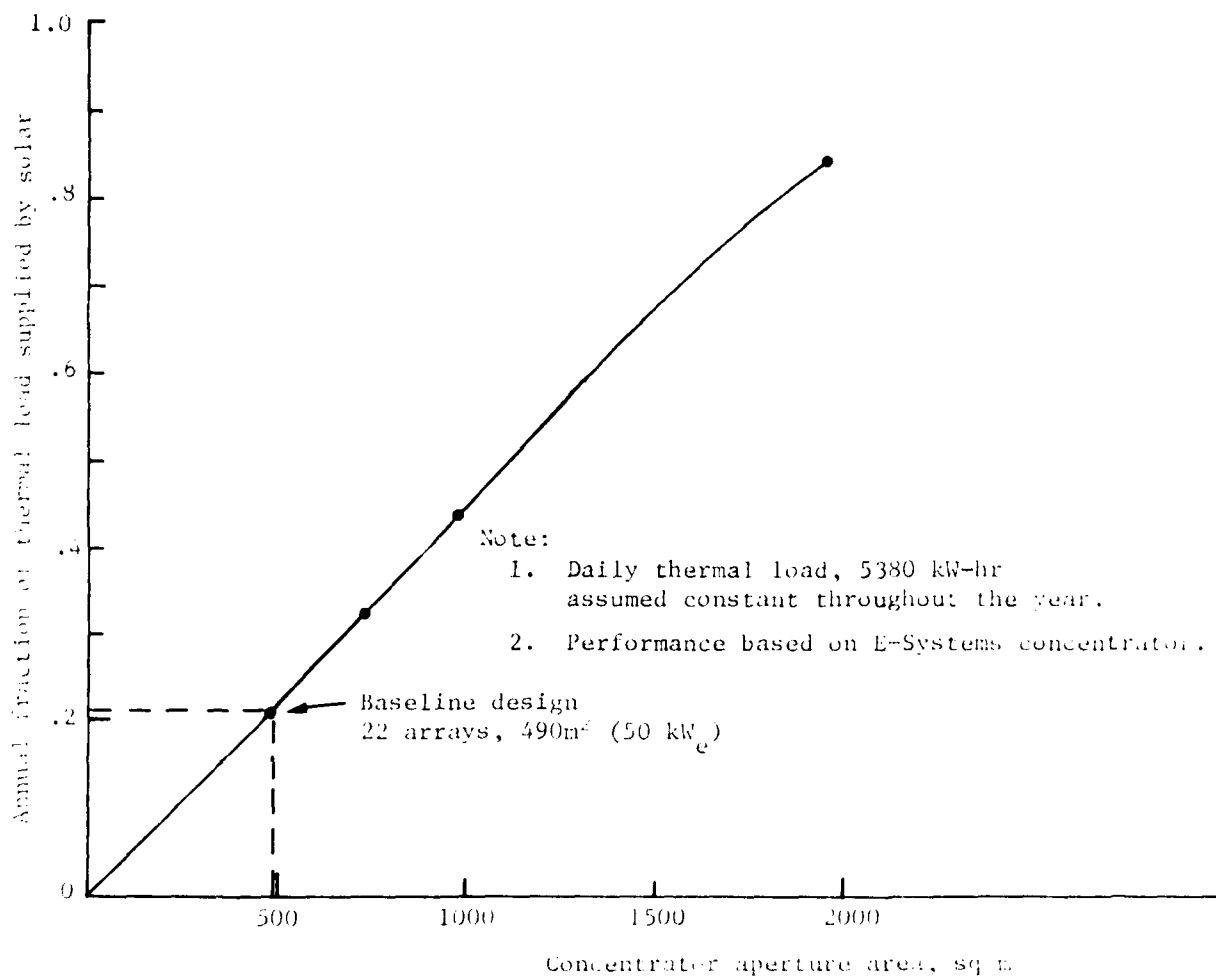
Figure 51. Projected thermal performance vs. system size.

Note:

1. Daily thermal load, 5380 kW-hr assumed constant throughout the year.

2. Performance based on E-Systems concentrator.

Baseline design
22 arrays, 490m² (50 kW_e)

100%
Incident solar
energy

8%
Reflection
losses

Lens

5%
Receiver truncation
losses

0.8%
Radiation
losses

2%
absorption +
scattering losses

85%
Transmitted -

0.9%
convection
losses

Trough

12.8%
reflection
losses

72.2% absorbed

Solar cells

0.5%
conduction
losses

Coolant passage

Insulation

11.4%
delivered electrical
energy (dc)

Operating conditions

I_{DN} = 946 Wm²

$T_{ambient}$ = 21.1°C

T_{cell} = 55°C

T_{fluid} = 45.6°C

m = 568 kg/hr

58.6%
delivered
thermal energy

Figure 52.   E-Systems Fresnel photovoltaic solar collector
energy balance.

SECTION V

COST ANALYSIS

Life-Cycle Cost Analysis

The Tinker AFB photovoltaic application was subjected to a life-cycle
cost analysis to determine the cost effectiveness of the system relative to
other energy alternatives. Obviously photovoltaics will not displace util-
ity-generated baseload electricity which can be purchased for 2.2 cents per
kilowatt hour at this time. However, the life-cycle cost results and sensi-
tivity projections, which are presented in this section, can be useful for
comparison with alternative energy sources for Air Force facilities.

Approach to Economic Analysis - The approach to the economic evaluation
of photovoltaics at Tinker AFB consisted of the following steps:

(a)   Determination of a nominal system size and the delivered electri-
        cal and thermal energy;

(b)   Estimation of initial 1979 installed costs which established a
        baseline for projected future system costs that accounted for:
        -   Learning curve improvements at higher production levels,
        -   Cell efficiency improvements,
        -   Cell cost reductions;

(c)   Calculation of levelized annual costs and benefits in constant
        1979 dollars for several near-term start-of-operation dates. The
        sensitivity of these costs to system initial costs, energy esca-
        lation scenario and system size effects was also investigated in
        the study.

Our method for computing levelized system costs is given in Appendix A.
The analysis is greatly simplified by the fact that the U.S. Government owns
the system. The effects of taxes, utility debt structure, and project fi-
nancing obviously can be ignored in the analysis. Levelized annual costs
for the photovoltaic system were computed from the following:

$$LAC = CRF \; (PW_{Fixed} + PW_{O\&M})$$
$$Charge$$

where:

    LAC   = Levelized annual cost

    CRF   = Capital recovery factor

$\text{PW}_{\text{Fixed Charge}}$ = Present worth of capital costs

$\text{PW}_{\text{O&M}}$ = Present worth of operating and maintenance costs

The capital recovery factor is given by:

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$$

where r is the discount rate and N is the system lifetime in years. A discount rate of 10% and life of 25 years were used in this analysis.

The present worth of the fixed charge component is given by:

$$\text{PW}_{\text{Fixed Charge}} = \frac{I_C \cdot FCR \cdot CCF}{CRF}$$

where:

I_C = Initial cost of the system

FCR = Fixed charge rate

CCF = Construction cost factor which accounts for interest during construction (ignored in this analysis)

The fixed charge rate (FCR) represents the yearly cost of ownership, including debt interest and principal payments, return on equity (not applicable for Air Force ownership), insurance, local taxes and the effect of taxes (obviously also not applicable here). For the case of zero taxes and insurance, the fixed charge rate reduces to the capital recovery factor (CRF).

The operation and maintenance term is given by:

$$\text{PW}_{\text{O&M}} = \frac{A_{\text{O&M}} \cdot M}{CRF}$$

where:

$A_{\text{O&M}}$ = Annual Operating and Maintenance Cost

M = Levelizing value for $Q_{\text{O&M}}$ costs which escalate over the lifetime because of inflation

The parameter M is computed from the following:

$$M = \frac{r(1+g)}{r-g} \cdot \frac{(1+r)^N - (1+g)^N}{(1+r)^N - 1}$$

where g is the annual inflation or escalation rate.

In order to compute levelized annual costs in constant base year (1979) dollars, a discount rate that accounts for inflation over the system life must be used. This rate, denoted by r', is given by:

$$r' = \frac{(1+r)}{(1+g)} - 1$$

The above equations can be re-arranged (see Appendix A) to express the levelized annual costs in constant dollars as follows:

$$LAC(\text{Constant } \$) = \frac{CRF'}{CRF} \cdot I_C \cdot FCR + A_{O\&M}$$

where CRF' is based on the inflation dependent discount rate r' defined here.

The levelized annual benefits resulting from the energy cost savings of the photovoltaic system are given by:

$$LAB(\text{Constant } \%) = \frac{CRF'}{CRF} \cdot M_f \cdot P_o \cdot E$$

where:

M_f = Levelizing value for the escalating cost of fuel

P_o = Energy price in year zero of system life

E = Quantity of energy displaced by PV system

If the levelized anual benefits exceed the levelized annual costs, the system is economically workable. The break-even system cost occurs when LAC and LAB are equal.

Scenario and Key Assumptions for Photovoltaic Economic Analysis - Table 27 summarizes the inputs to our life-cycle cost analysis for the Tinker electroplating application. The baseline escalation scenario was taken from the Battelle Study (Ref 1) for their "high" forecast, which was hypothesized in 1977. Recent events in 1979 have now raised oil prices to the point where Battelle's "high" scenario now appears to be a moderate position.

TABLE 27. BASELINE SCENARIO FOR LIFE-CYCLE COST ANALYSIS

System Life	25 years
Maintenance	1.5% per year of initial cost
Discount rate	10%
Inflation	5%
Salvage value	0
Replacement costs	0 (included in maintenance)

No financing of initial cost (i.e., 100% down payment)

Energy cost escalation* (including inflation)

	Electricity	Natural gas
1980-1985	11-9%/yr	9.5%/yr
1986-1990	7.4	11.1
1990-2005	6.6	7.5

*Based on medium escalation scenario in Battelle AFLC Energy Study, June 1978

Our estimates of installed costs (in 1979 dollars) for our selected preliminary design are described in Initial Cost Summary, which follows. In projecting these estimates into the 1980s, the assumptions shown in Table 28 were made. Notice that only silicon technology was considered in the projections. Other cell materials would require higher concentration levels (500-2000X) with major system differences from the preliminary design evaluated in this study.

Life-Cycle Cost Results - The key parameter in the evaluation of the life-cycle cost for a photovoltaic system is the estimate of initial installed costs for the total system. The following section presents the details of the cost estimates. Figure 53 shows the resulting total system-installed cost in 1979 dollars per peak watt for a nominal 50 kW photovoltaic/thermal system. The scenario for improvements in concentrator cell efficiencies is also shown in Figure 53.

TABLE 28. CELL EFFICIENCY AND COST PROJECTIONS FOR PHOTOVOLTAIC ECONOMIC ANALYSIS

Year	Cell efficiency at 50°C (%)	Cell cost 1975 $ ($/cm²)
1982	16	0.25
1985 +	18	0.25

95
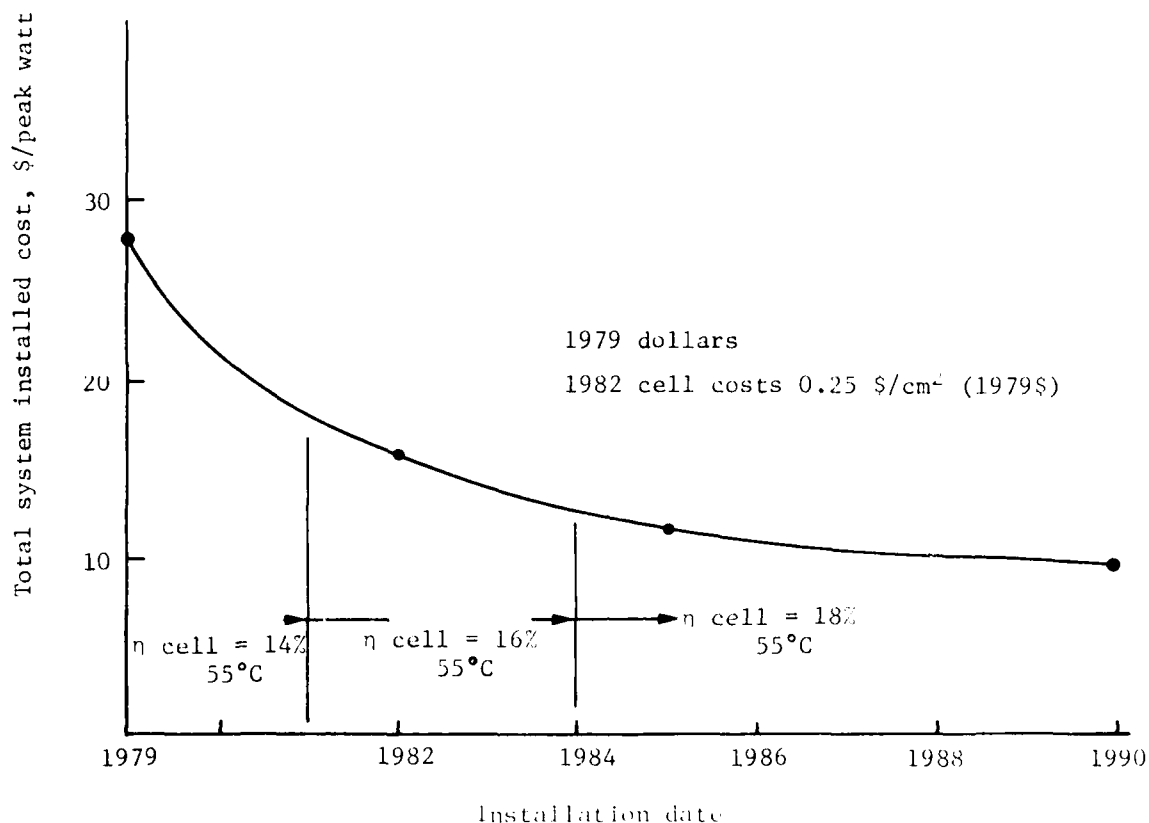
Figure 53. Total cost per peak watt for 50 kW actively cooled
photovoltaic concentrator system.

Given the above initial costs and the baseline scenario for the financial parameters shown in Table 27, the levelized annual costs and benefits for the 50 kW system were computed for project start of operation dates ranging from 1979 out to 1990. Figure 54 shows the sensitivity of the annual benefits to the rate of price escalation for gas and electricity at Tinker AFB. The range of escalation rates chosen for gas and electricity were intended to bracket the effect of fuel escalation on the levelized system costs.

Inspection of Figure 54 shows that if the fuel costs for the existing system rise at 16% per year, then the 50 kW system could be economically justified in 1988. If fuel costs rise at 12% per year or less, the solar system would not be economically practicable until the late 1990s. No cost projections were made beyond 1990 system startup dates due to the large uncertainties in initial costs and fuel escalation scenarios.

The preceding analysis was repeated for nominal system sizes of 100 kW and 500 kW to investigate potential cost reductions due to large scale installations. Savings in design, integration, and checkout activities accrue

91
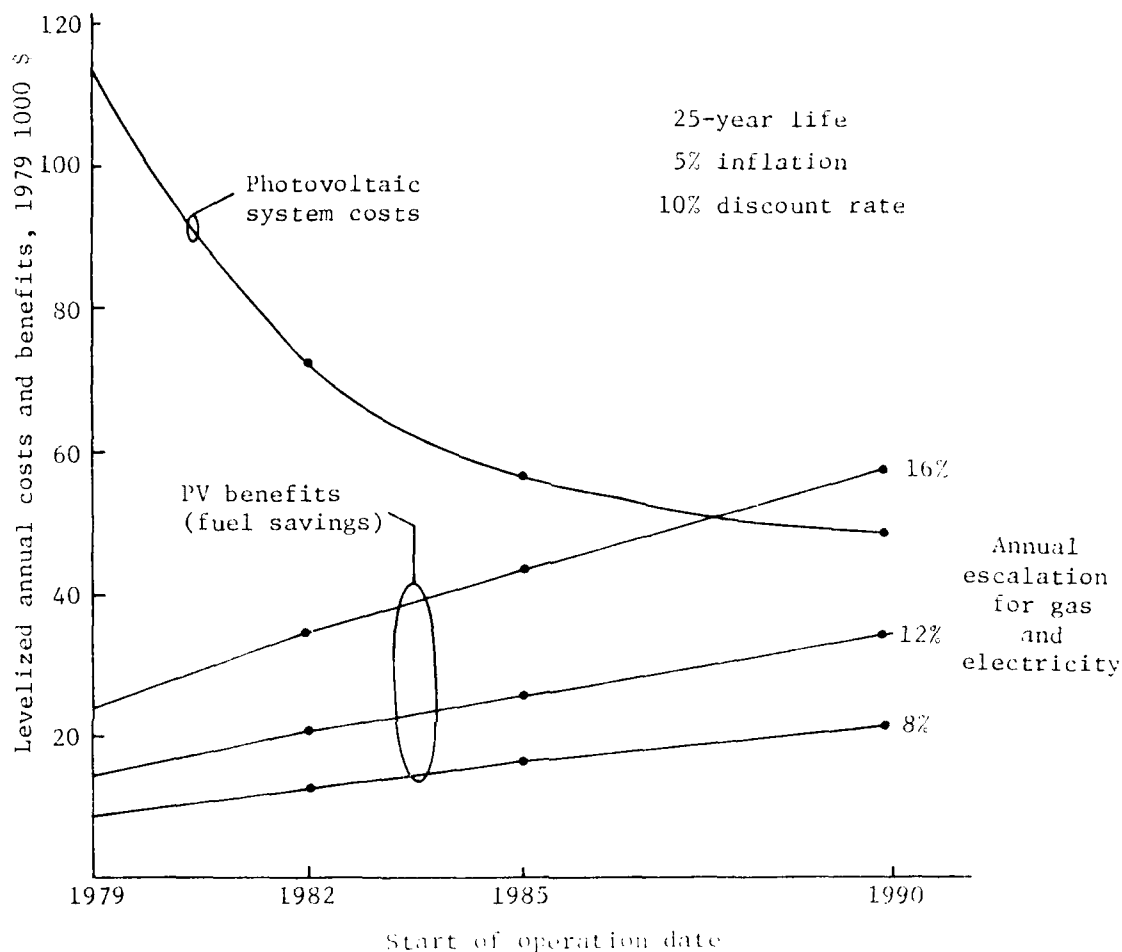
Figure 54.   Annual costs and benefits for 50 kW photovoltaic
concentrator system.

for these larger systems. Figure 55 shows the projected cost in dollars per peak watt for the 100 kW and 500 kW system sizes. Figures 56 and 57 show the corresponding levelized annual costs and benefits for the baseline economic scenario. The break-even points (i.e., LAC = LAB) for the 100 kW and 500 kW systems move up to 1985 and 1984, respectively, for the 16% fuel escalation, thus reflecting the increased cost effectiveness of the larger systems.

Initial Cost Summary - Table 29 summarizes our estimates of labor and material required to build and install the 50 kW photovoltaic system at Tinker AFB. Key assumptions made in the estimating process included:

(a)   Solar cell costs will meet DOE's goal of 0.25 $/cm^2 (in 1975 $) by 1982. These cell costs were assumed to increase with inflation from 1982 on.
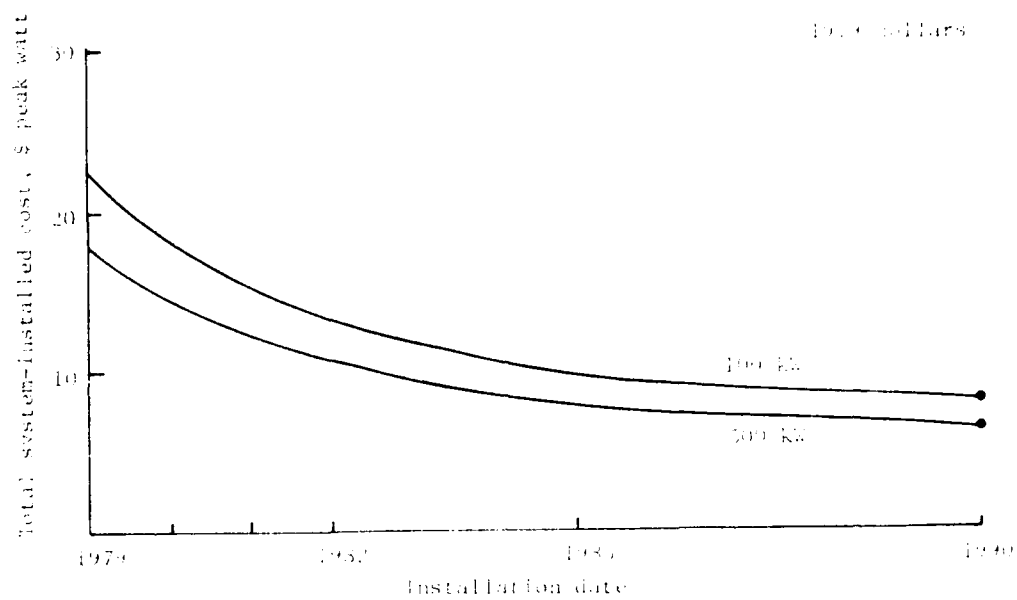
Figure 55. Total cost per peak watt for 100 kW and 500 kW
photovoltaic systems.
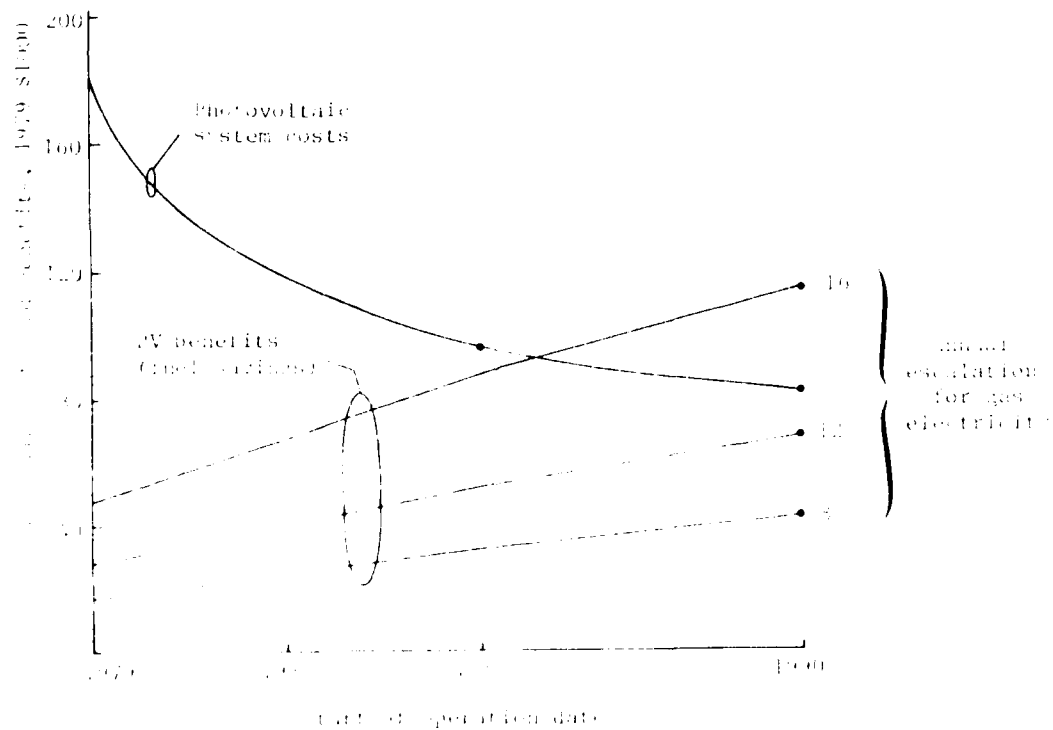
Figure 56. Annual costs and benefits for 100 kW photovoltaic system.
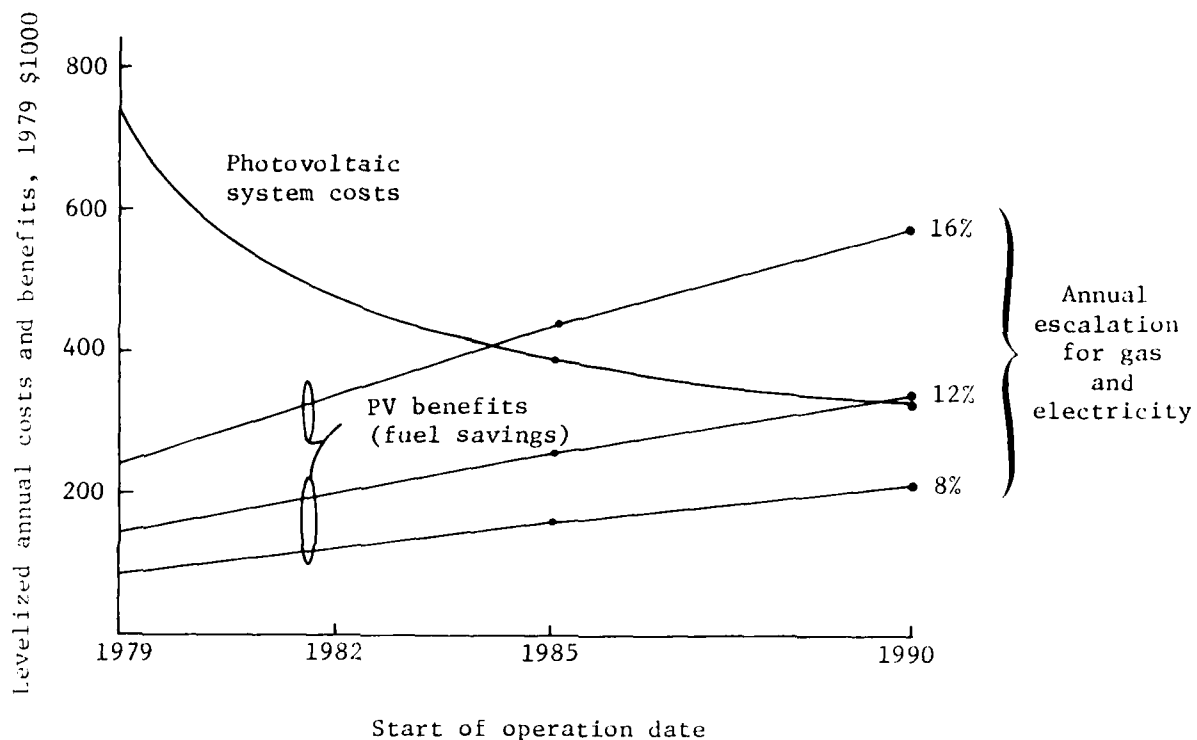
Figure 57. Annual costs and benefits for 500 kW photovoltaic system.

TABLE 29. INITIAL HARDWARE AND INSTALLATION COST, CURRENT YEAR DOLLARS

| Cost elements | Material, $1000 | | | | Labor, manmonths | | | | | | | | |
| | | | | | Design fab/test | | | | Install | | | |
	'79	'82	'85	'90	'79	'82	'85	'90	'79	'82	'85	'90
Subsystems												
Photovoltaic Array (22 k-Sys PV arrays)	500	352	352	366	5	3	2	2	5		3	
Power conditioning	38	44	44	44	3	3	2	1	3	3	2	3
Power distribution	35	40	46	59	4	4	2	1	3	3	2	2
Instrumentation & data recording	51	30	30	30	3	3	1	1	2	2	3	3
Thermal & structural	115	137	158	202	5	5	4	4	5	5	5	5
Project management					6	6	4	3	2	2	2	
System integration					6	6	3	3	10	2	3	5
A&E					3	3	4	4	2	2	3	3
Miscellaneous (tooling, equipment & handling, shipping, etc)	50	50	50	50								
Total	901	653	670	731	35	33	21	17	32	30	23	

(b)   Solar cell laydown costs increase with inflation from 1982 on, and at the same time cost reductions are being achieved on a 90% learning curve.

(c)   Assumed annual production levels for the E-Systems concentrator were:

1982 2.5×10^3 m^2

1985 10^4 m^2

1990 10^5 m^2

(d)   90% learning curve for the E-Systems concentrator.

The labor and material estimates were priced out for assumed project dates off 1979, 1982, 1985, and 1990. Overhead rates were then applied to the cost elements to arrive at the cost summary shown in Table 30. The bottom line costs were then converted to 1979 $ and used to compute the installed cost per peak watt, which have been presented above in Figure 53.

TABLE 30.   INITIAL COST SUMMARY FOR 50 KW PHOTOVOLTAIC SYSTEM, $1,000

	1979	1982	1985	1990
Direct costs				
PV concentrators	500	352	342	346
Other materials	301	301	328	385
	801	653	670	731
Labor	183	197	148	160
Indirect costs				
Design, test labor (100%)	115	97	67	70
Installation labor (63%)	68	63	51	57
General and administrative overhead, 17%	199	172	159	173
Fee, 10%	137	118	109	119
Total, current $	1510	1302	1204	1310
(1979$)	1510	979	780	665

Inflation scenario for current $ estimate:	1979	14%
	1980-82	8%
	1983+	5%

The above process was repeated for the 100 and 500 kW systems, with the resulting cost summaries shown in Tables 31 and 32. As expected, significant savings over the 50 kW system were projected in design, fabrication, and test labor areas.

Cost Estimates for E-Systems Photovoltaic Arrays - Array material costs were accumulated by E-Systems on their PRDA Phase I contract (Ref 7) using DOE guidelines for material unit costs. Table 32 shows the resulting cost breakdown for the array materials when purchased in large quantities in 1979 $ (except for the cell costs, which are shown in 1975 $). E-Systems is currently bidding thermal concentrator projects at 323 $/m^2, FOB their Dallas plant. Their photovoltaic concentrator presently costs slightly over 1000 $/m^2, largely due to the high costs for solar cells. This 1000 $/m^2 figure was used in this study for 1979 cost estimate for the E-Systems concentrators.

TABLE 31. INITIAL COST SUMMARY FOR 100 kW PHOTOVOLTAIC SYSTEM, CURRENT $1,000

	1979	1985	1990
Direct costs			
PV concentrators	1000	684	692
Other materials	481	576	690
	1481	1260	1382
Labor	213	183	185
Indirect costs			
Design, test labor (100%)	36	67	70
Installation labor (63%)	80	73	72
General & administrative Overhead, 17%	316	269	290
Fee, 10%	218	185	200
Total, current $	2394	2037	2199
(1979 $)	2394	1320	1116
Inflation scenario for current $ estimate: 1979			11%
1980-82			8%
1983+			5%

96

TABLE 32. INITIAL COST SUMMARY FOR 500 kW PHOTOVOLTAIC
SYSTEM, CURRENT $1,000

	1979	1985	1990
Direct costs			
PV concentrator	5000	3420	3460
Other materials	1766	2222	2678
	6766	5642	6138
Labor	429	430	414
Indirect costs			
Design, test labor (100%)	86	67	70
Installation labor (63%)	216	229	217
General & administrative overhead, 17%	1274	1082	1162
Fee, 10%	877	745	800
Total, current $	9649	8196	8802
(1979$)	9649	5311	4467

Inflation scenario for current $ estimate:	1979	14%
	1980-82	8%
	1983+	5%

SECTION VI

CONCLUSIONS AND RECOMMENDATIONS

The basic plating facility load requirements were determined to be 733 kW_e/day and 446 kW_t/day. The modular size of 50-kW photovoltaic system was found to be acceptable. The most desirable location for the photovoltaic array is the building roof adjacent to the plating facility. This roof has sufficient surface area to accommodate several hundred kW of photovoltaic arrays.

The simplest and most cost effective photovoltaic system configuration is that of an all-electric system consisting of array and inverter with peak power tracker, and no energy storage (electrochemical or thermal). Thermal distribution system can interface directly with the plating facility but was found to be costly because of extensive distribution piping and exotic heat exchangers required.

The initial installed cost of an actively cooled PV/thermal system was determined to be $28.00/W and $25.00/W for an electric-only system. The life-cycle cost analysis indicated that the photovoltaic power system cannot compete economically in energy and capacity displacement with conventional power plant in the immediate future.

SECTION VII

REFERENCES

1. D. Moore, and D. Locklin: A Study to Determine the Desirability and
   Feasibility of New Alternative Energy Systems for the AFLC Installa-
   tions. Batelle Columbus Laboratories, Contract F33601-77-90551, June
   1978.

2. E. C. Boes et al.: Availability of Direct, Total, and Diffuse Solar
   Radiation to Fixed and tracking collectors in the USA. SAND 77-0885
   Sandia Laboratories, Albuquerque, NM (1977).

3. SOLMET - Hourly Solar Radiation - Surface Meteorological Observations,
   Users Manual TD-9724, prepared for the U.S. Department of Energy by the
   National Climatic Center, Ashville, NC, Dec. 1977.

4. C. M. Randall, M. E. Whitson, Jr.: Hourly Insolation and Meteorological
   Data Bases Including Improved Direct Insolation Estimates, Aerospace
   Report No. ATR-78(7592-1), SAND78-7047, December 1977.

5. L. W. James: Spectral Splitting Concentrator Array, Photovoltaic Con-
   centrator Technology Development Project, SAND 79-0557, April 4-5, 1979.

6. D. Jardine, and R. Jones: A 64 KW Concentrating Photovoltaic Applica-
   tion. Kaman Sciences, DOE-CS-24278-1, Vol II, Appendix A, 1979.

7. T. A. Kins, and R. Kirkpatrick: Cost Data Collection from Solar Demon-
   stration Projects. Proceedings of Operational Results for Solar Heating
   and cooling Systems Conference, SERI/TP-49-063, Colorado Springs,
   Colorado, November 1978.

8. M. O'Neill: A Fresnel/Photovoltaic concentrator Application Experiment
   for the Dallas-Fort Worth Airport, Phase I - System Design, Final Tech-
   nical Report, DOE/CS/95311-1, March 1979.

9. R. Giellis, D. Hull: SOLCOST - A Solar Energy Design Program. Proceed-
   ings of Systems Simulation and Economic Analysis Conference, January
   23-25, 1980 San Diego, Cal. (SERI/TP-351-431 Solar Energy Research
   Institute, Golden, Colorado).

APPENDIX A

ROOF LOADING EVALUATION FOR
PHOTOVOLTAIC SYSTEM BY TINKER AFB
FACILITY CIVIL ENGINEER

DEPARTMENT OF THE AIR FORCE
HEADQUARTERS OKLAHOMA CITY AIR LOGISTICS CENTER (AFLC)
TINKER AIR FORCE BASE OKLAHOMA 73145

25 May 1979

Roger T. Giellis
Martin Marietta Aerospace
Post Office Box 179
Denver CO 80201

Dear Roger

Thank you for the copy of the progress report. With reference to the
request in your letter, I forwarded the data on the candidate systems
to Civil Engineering. Enclosed you will find their preliminary analysis
concerning the roof loading capabilities of building 3001 to support
the items listed in table A1. Subsequent action on the E-system
configuration revealed it would be feasible to column line this structure
on an east and west basis by using external supporting beams above the
roof to support the legs or ground mounts. This installation could
possibly be located over the low bay roof area.

If you desire any additional information, please don't hesitate to
call. I intend to be on leave during the first two weeks of June 1979;
however, Mr. Charles Brittain will be available to handle any requests
during the interim.

Sincerely

Jack A. Martin

JACK A. MARTIN
Logistics Research & Systems Division
Directorate, Plans & Programs

1 Atch
2854/DEEE Ltr, 17 May 79

101

17 MAY 1979

REPLY TO
ATTN OF: DEEE (Mr. Tateya, 5236)

SUBJECT: Roof Loading Evaluation for a Photovoltaic System (Your Ltr, 2 May 79)

TO: OC-ALC/XR

1. Preliminary investigation on roof of Bldg 3001, for subject loading, disclosed the following:

    a. The Turntable-Parabolic Troughs (general electric) could possibly be installed over the high bay roof area (between column lines X-Y). However, because of the excessive imposed loads to the roof trusses, the existing bridge crane operation would have to be eliminated throughout the high bay area. The low bay roof area does not have enough open area to accommodate the large 140 ft diameter system. Complete structural analysis and review of proposed system would be required.

    b. The Pedestal-Point Focus Fresnel Lens (Martin Marietta) and pedestal-parabolic troughs (Honeywell) could possibly be installed over the low-bay roof area. These pedestals could be located directly over the existing building columns (50 ft by 60 ft spacings). The existing columns would have to extended through the roof to support any pedestal system.

    c. No sketch was provided for the $1\frac{1}{2}$ axis tracker linear fresnel (E-systems), therefore, it was not evaluated.

    d. Installation of a storage tank over the lean-to does not appear to be feasible, because it would overload the footings. Recommend storage tank be located on the ground.

2. If additional information is desired, please advise.

HERBERT LANG
Deputy Base Civil Engineer

APPENDIX B

SOLCOST THERMAL ANALYSIS APPLICATION TO TINKER AFB
ELECTROPLATING FACILITY

INTRODUCTION

The SOLCOST solar energy design program (Ref B1) was developed in 1976 under the auspices of the U.S. Department of Energy. The program predicts the annual solar system performance for a range of collector areas and then determines the optimum collector area based on a life-cycle cost analysis. SOLCOST is based on a detailed simulation for an average day for each month.

An iterative procedure was developed for Version 2.0 to assist SOLCOST users in estimating the starting collector inlet temperature, which is the key to the SOLCOST average-day method. The procedure consists of an iterative process that checks the storage temperature at dawn against the previous dawn value. If the difference is outside a reasonable limit, the average-day analysis is repeated using a refined estimate of the dawn storage temperature. The important element of this one-day simulation is the energy balance on the storage tank. All energy delivered to storage either satisfies the load or is lost through the tank insulation. The methodology of this procedure is described below.

THERMAL ANALYSIS METHOD (Excerpted from Ref B1)

The SOLCOST solar system evaluation method is based on an hour-by-hour simulation performed one day per month. Key assumptions made in the analysis include:

(a) Collector efficiency is characterized by a straight line with intercept $F_r \tau\alpha$ and slope $F_r U_L$;

(b) Unstratified liquid storage;

(c) Collector inlet temperature is equal to storage tank temperature (if a heat exchanger is present, the collector parameters must be derated with the technique described by F. de Winter (Ref B2).

Ref. B1. R. Giellis: SOLCOST - A Solar Energy Design Program. presented at Systems Simulation and Economic Analysis Conference, January 23-25, 1980 San Diego, Cal, SERI/TP-351-431.

B2. F. deWinter: "Heat Exchanger Penalties in Double-Loop Solar Water Heating Systems." Solar Energy, 17, p235, 1976.

The essence of the average-day approach consists of performing an hourly energy balance on the solar system with the collected solar energy term weighted with a simple factor that accounts for the long-term variability in the incident solar radiation. This weighting factor PP is a direct function of the long-term daily average horizontal insolation available at the site. It is computed from the relation

$$PP_i = \frac{H_h - H_{hd,cloudy}}{H_{h,clear} - H_{hd,cloudy}} \qquad [B-1]$$

where

PP_i - weighting factor for month i,

H_h = daily average total horizontal insolation for month i (from SOLMET data in SOLCOST weather data bank),

$H_{h,clear}$ = SOLCOST model-generated clear-day total horizontal insolation for month i,

$H_{hd,cloudy}$ = SOLCOST model-generated cloudy-day total horizontal insolation for month i.

The terms $H_{h,clear}$ and $H_{hd,cloudy}$ are computed from integration of the clear-day and cloudy-day terms I_{clear} and I_{cloudy} generated by the SOLCOST radiation model.

Iterative Procedure for Starting Inlet Temperature - An iterative process is used to determine the long-term average dawn storage temperature for each month of the year. Four steps are performed each hour in the one-day simulation, including:

Step 1 - Collector efficiency given by

$$\eta_c = F_r \tau\alpha - F_r U_L (T_{in} - T_{amb})/I \qquad [B-2]$$

where

c - collector efficiency,

T_{in} - collector inlet temperature,

T_{amb} - ambient temperature constructed with a cosine function of T_{min} and T_{max},

I - solar irradiance (I_{clear} or I_{cloudy}),

$F_r \tau\alpha$ - intercept of collector efficiency curve (input),

$F_r U_L$ - slope of collector efficiency curve (input).

Collector efficiencies η_{clear} and η_{cloudy} are computed for clear-day and cloudy-day values of the solar irradiance I_{clear} and I_{cloudy} using the same ambient temperature and inlet temperature for each calculation;

Step 2 - Useful collected solar energy

$$QU = (PP\eta_{clear} I_{clear} + (1-PP)\eta_{cloudy} I_{cloudy})\eta_t CA \qquad [B-3]$$

where

QU = useful solar energy from the collector,

PP = weighting factor (defined above),

η_{clear} = collector efficiency, clear day

η_{cloudy} = collector efficiency, cloudy day

I = solar irradiance,

CA = collector aperture area,

η_t = transport efficiency (i.e., for piping losses from collector to storage);

Step 3 - Load determination, a user input (on a daily basis) that is then removed from the thermal system on an hourly basis as a function of ambient temperature or by a user-specified load distribution profile;

Step 4 - Storage tank temperature that is assumed to be the same as the collector inlet temperature in SOLCOST. The new storage tank temperature is calculated by summing the energy added to storage (Step 2) and the energy removed from storage (Step 3) and dividing by the storage capacity and adding this to the old storage tank temperature as

$$TS_{new} = TS_{old} + (QU - QLOSS - LOAD)/(GF*CA*8.337) \qquad [B-4]$$

where

TS_{new} = new storage tank temperature,

TS_{old} = old storage tank temperature,

QU = useful energy collected,

QLOSS = storage losses,

LOAD = system load,

GF = gallons of storage per square foot of collector,

CA = collector area.

The storage tank temperaturee has user-imposed upper and lower limits. This means that the storage temperature cannot rise above a specified value (default is 200°F) and cannot drop below another specified value (default is 100°F).

These four steps are repeated every hour from sunrise until sunset. At sunset the remainder of the load is removed and the final storage temperature is computed (subject to the minimum storage temperature constraint). At this point a final storage tank temperature, which is the storage tank temperature after the load was removed, is available. This final storage tank temperature is then compared with the storage tank temperature used to start the hour-by-hour calculation. If they differ by more than some tolerance (default is 1°F), a new starting storage tank temperature is calculated and the hour-by-hour simulation is repeated. The new starting storage tank temperature is based on the calculated final storage tank temperature, the useful energy collected, and the load. When the temperature convergence criteria are satisfied, monthly values for the energy terms are computed by simply multiplying the daily terms by the number of days in the month. This process is repeated for each month of the year.

SOLCOST Application to Tinker Electroplating Facility - Table B1 lists the SOLCOST inputs used for the Tinker AFB Analysis. The E-Systems collector parameters were input via lines 14 and 15, and the thermal capacitance of th plating tanks was accounted for with line 17 where a value of 13.07 gallons/ft^2 of aperture area was entered because the aperture area for a 50 kW$_e$ system is 490 m^2 (5275 ft^2, input on line 21). The minimum allowable plating tank temperature was input at 110°F.

Four runs were made with the collector aperture area being increased in each run to simulate larger systems. Key results from the baseline 50 kW$_e$ (490 m^2, 5275 ft^2 aperture) SOLCOST run include the monthly thermal system energy balance shown in Table B2. The conventional system energy shown in Table B2 represents the input energy requied by the existing natural gas-fired boiler to heat the low temperature tanks in the plating facility. The energy balance by month is given by:

SOLAR + AUXILIARY = LOAD

or   Useful Solar + boiler (Aux.Energy) = boiler (Conventional Energy)
     Energy

A value of 60% was input for the boiler efficiency. Another key output from the analysis is the temperature summary by month for the plating tanks (i.e., storage). Table B3 shows the plating tanks did not budge off their lower set point of 110°F for the 50 kW$_e$ system. Also shown in Table B3 is a storage insulation loss column, which has been set to zero for the Tinker AFB analysis. This was done because the actual heat losses from the plating tanks were accounted for in the load term input to SOLCOST.

106

TABLE B1. SOLCOST INPUTS FOR TINKER AFB ELECTROPLATING FACILITY TANK
HEATING ANALYSIS

SOLCOST INPUT LINE NO.	DATA VALUE	PARAMETER DESCRIPTION
1	1	HOT WATER HEATING SYSTEM
2	0.73	TRANSPORT EFFICIENCY (I.E., PIPING LOSSES)
3	110.	COLLECTOR INLET TEMP (INITIAL GUESS)
4	1	NATURAL GAS FOR REFERENCE SYSTEM FUEL
5	0.60	60% EFFICIENCY FOR N.G. REFERENCE
6	1	NATURAL GAS FOR AUXILIARY
7	0.60	60. EFFICIENCY FOR N.G. AUXILIARY SYSTEM
10	21	COLLECTOR TYPE, E-SYSTEMS
11	8	RADIATION INPUT, DIRECT NORMAL ONLY, FULL TRACKING
14	0.57	COLLECTOR EFFICIENCY (INTERCEPT ON CURVE)
15	0.5035	COLLECTOR EFFICIENCY (EFF AT 0.5)
17	13.07	THERMAL STORAGE PER UNIT COLLECTOR AREA, GAL/SQ FT (TOTAL PLATING TANKS VOLUME 68950 GALLONS)
21	3	FLAG TO RUN SINGLE COLLECTOR AREA ONLY
22	5275.	COLLECTOR AREA, SQ FT FOR 22 E-SYSTEMS ARRAYS
25	218	LOCATION FLAG FOR OKLAHOMA CITY
27	1.0	CLEARNESS FACTOR
36	0.90 0.84 0.84 0.85 0.83 0.86 0.83 0.79 0.85 0.87 0.86 0.90*	CLEARNESS NUMBERS BY MONTH
41	3	LOAD METHOD FLAG
49	18.36	DAILY TOTAL PLATING TANK LOAD, MILLION BTUS/DAY
141	0.05	CONVERGENCE CRITERIA ON DAWN STORAGE TEMPERATURE
143	110.	MINIMUM ALLOWABLE PLATING TANK TEMPERATURE
145	1	FLAG TO PRINT PLATING TANK TEMPERATURE
150		ARRAY OF HOURLY LOAD REMOVAL RATE FRACTIONS

0.04166   0.04166   0.04166   0.04166   0.04166   0.04166
0.04166   0.04166   0.04166   0.04166   0.04166   0.04166
0.04166   0.04166   0.04166   0.04166   0.04166   0.04166
0.04166   0.04166   0.04166   0.04166   0.04166   0.04166

| 156 | 0.0 | ZERO STORAGE TANK INSULATION LOSSES BECAUSE THIS IS ACCOUNTED FOR IN THE LOAD |

TABLE B2. SOLCOST COMPUTED SOLAR FRACTIONS AND MONTHLY ENERGY BALANCE,
50 kW$_e$ SYSTEM

ENERGY BALANCE BY MONTH FOR 5280.0 SQ FT COLLECTOR

MONTH	FRACTION BY SOLAR	AVERAGE USEFUL SOLAR PER DAY (BTU DAY-SQ FT)	TOTAL USEFUL SOLAR ENERGY (MIL BTU MO)	AUXILIARY ENERGY (MIL BTU MO)	CONVENTIONAL SYSTEM ENERGY (MIL BTU MO)
1	0.159	551.3	90.24	798.20	948.60
2	0.183	635.8	93.99	700.15	856.80
3	0.209	727.8	119.12	750.07	948.60
4	0.226	787.4	124.73	710.12	918.00
5	0.234	812.5	132.98	726.96	948.60
6	0.266	924.1	146.38	674.04	918.00
7	0.267	929.0	152.07	695.16	948.60
8	0.254	884.5	144.77	707.31	948.60
9	0.226	785.8	124.48	710.54	918.00
10	0.214	743.9	121.77	745.66	948.60
11	0.180	624.6	98.94	753.09	918.00
12	0.153	533.6	87.34	803.03	948.60
ANNUAL	0.214		1436.81	8774.32	11169.00

NOTE 1   CONV ENERGY AND SOLAR AUXILIARY ENERGY ARE GROSS VALUES
(I.E., THEY INCLUDE TANK INSULATION AND/OR COMBUSTION LOSS)

TABLE B3. PLATING TANK (STORAGE) TEMPERATURE SUMMARY,
SOLCOST OUTPUT, 50 kW$_e$ SYSTEM

TEMPERATURE AND ENERGY INFORMATION FOR COLLECTOR AREA 5280.

MONTH	STORAGE DAWN (°F)	TEMPERATURE MAXIMUM (°F)	AVERAGE	STORAGE LOSSES (BTU DAY)	NUMBER OF ITERATIONS
1	110	110	110	0	1
2	110	110	110	0	1
3	110	110	110	0	1
4	110	110	110	0	1
5	110	110	110	0	1
6	110	110	110	0	1
7	110	110	110	0	1
8	110	110	110	0	1
9	110	110	110	0	1
10	110	110	110	0	1
11	110	110	110	0	1
12	110	110	110	0	1

APPENDIX C

LIFE-CYCLE COST METHOD

Levelized Annual Cost

True life-cycle cost analysis must necessarily consider the timing of costs and benefits as well as the magnitude. A simple approach is to compare Levelized Annual Benefits (LAB), which represents system energy savings with the Levelized Annual Cost (LAC), the levelized dollar amount required to own, operate, and mantain a system during each year of the life of the system. Specifically, the levelized annual cost accounts for:

(a) "Paying off" system capital costs

(b) Paying for operating and maintenance expenses

(c) Paying taxes

(d) Paying a return to investors and interest to creditors

(e) Building a capital fund for periodic component replacement, over-haul, and retirement of debt.

The levelized annual cost, denoted by LAC, is given by:

$$LAC = CRF \times PW \qquad [1]$$

where CRF is the capital recovery factor and PW is the present worth of the year-by-year revenue requirements throughout system life.

The following sections describe the analytics for computing LAC & LAB as applied to photovoltaic systems for various user-types.

Capital Recovery Factor, CRF - The capital recovery factor is the uniform periodic payment, as a fraction of the original principal, that will fully repay a loan (including the interest rate). The interest rate used to calculate CRF is called the discount rate and represents the weighted average cost of capital. Analytically, the capital recovery factor is given by:

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1} \qquad [2]$$

where r is the appropriate annual discount rate and N is the system lifetime in years. The discount rate, r, varies with the application. Values of 0.09, 0.072, and 0.10 have been used for the utility, residential, and intermediate applications, respectively. Federal projects require a discount rate of 0.10.

Present Worth, PW - The present worth is analogous to that amount that, if deposited in an interest bearing account at the discount rate, would permit annual withdrawals to pay all system costs and diminish to zero at the end of system life. For evaluation of PV systems, the PW is composed of two components: (1) a component accounting for capital costs, and (2) a component accounting for the cost of operation and maintenance (O&M).

The total present worth is given by:

$$PW = PW_{fixed\ charge} + PW_{O\&M} \tag{3}$$

The fixed charge component is given by:

$$PW_{fixed\ charge} = \frac{I_C \cdot FCR \cdot CCF}{CRF} \tag{4}$$

Here, I_C, is the total capital cost of the system and CCF is the construction cost factor accounting for interest during construction of the PV system.

The parameter FCR is the fixed charge rate and represents the yearly cost of ownership, expressed as a percentage of the capital investment, I_C. These costs consist of capital outlay, taxes, and insurance. An explanation of the fixed charge rate and its derivation is given in the following subsection.

The second component in equation (3) accounts for system operation and maintenance. This is given by:

$$PW_{O\&M} = \frac{A_{OM} \cdot M}{CRF} \tag{5}$$

This is similar in form to equation (4), but with different parameters. A_{OM} is the cost of operating and maintaining the system.

The parameter M, defined as the levelized value of an escalating cost stream, accounts for the fact that A_{OM} is increasing over the lifetime of the system because of inflation.

$$M = \frac{r\ (1 + g)}{r - g}\ \frac{(1 + r)^N - (1 + g)^N}{(1 + r)^N - 1} \tag{6}$$

where g is the annual inflation or escalation rate.

Substituting equations (4) and (5) into equation (3) yields:

$$PW = \frac{1}{CRF} \, I_C \cdot FCR \cdot CCF + M \, (A_{OM}) \qquad [7]$$

Fixed Charge Rate - The fixed charge rate (FCR) represents the yearly cost of ownership, expressed as a percentage of the investment, I_C. These costs consist of debt interest and principal payments, return on equity (where applicable), insurance, local taxes, and the net effect of Federal taxes. The concept of the fixed-charge rate comes from electric utility financial analysis, but has proved to be applicable and convenient in the analysis of other sectors as well.

The residential energy user has one important difference from other energy consumers in that energy is not a tax deductible expense. The effect is best shown by example. Consider an industrial and a residential user in 48 and 20 percent tax brackets, respectively. Assume each has $1000 of before-tax income and is evaluating $100 energy purchase:

| | Corporation | | | Homeowner | |
	Without energy	With energy		Without energy	With energy
Gross income	1000	1000	Gross income	1000	1000
Deductible expenses	0	100	Deductible expenses	0	0
Taxable income	1000	900	Taxable income	1000	1000
Federal taxes (48%)	480	432	Federal taxes (20%)	200	200
Net income	520	468	Net income	800	800
			Less energy	–	100
					700

After tax energy cost = $520 - 468 = $52

Thus, although the homeowner pays the full $100, the corporation effectively pays only $52 [$100 x (1 - tax rate)] because taxes are reduced by $48. It is due to this tax effect that costs of alternative energy systems must be evaluated on an after-tax basis for the homeowner and on a before-tax basis for the corporation. Only in this way can system costs be compared with prevailing energy costs.

A detailed discussion of fixed charge rate, its various components, and corporate tax effects is presented in The Cost of Energy from Utility-Owned Solar Electric Systems (C-1). The residential sector presents a much simpler case. Assuming a 9 percent loan for a homeowner in a 20 percent incremental tax bracket, the effective after-tax rate can be shown to be 7.2 percent [0.9 x (1 - 0.2)]. Computing the appropriate CRF and adding local taxes and insurance yields the fixed charge rate. For example, assume a 10-year life system and 2.5 percent for local taxes and insurance:

$$FCR = \frac{CRF \; (1.072)^{10}}{1.072^{10} - 1} + 0.025 = 0.1687$$

Typical fixed charge rates (FCR) as a function of system life N and application are tabulated here:

System life in years	FCR Utility	Residential	Industrial/commercial
10	0.23	0.17	0.27
20	0.19	0.12	0.23
30	0.18	0.10	0.22
50	0.18	0.10	0.22

Levelized Annual Cost in Current Dollars

If equation (7) is substituted into equation (1):

$$LAC = I_C \cdot FCR \cdot CCF + M \; (A_{OM}) \qquad [8]$$

In this case, the levelized annual cost is expressed in terms of current dollars.

Expressing LAC in current dollars establishes equal yearly costs over the system life. This is analogous to the case of a home mortgage. The homeowner borrows money at some interest rate. It is paid back in equal monthly (hence, yearly) installments over the life of the mortgage (i.e., he pays \$X/month in the first year and \$X/month in the 30th year).

Levelized Annual Cost in Constant Dollars

An alternative method of expressing levelized annual costs is to reference the costs to a particular base year, e.g., 1976. The result is the levelized annual cost in constant (base year) dollars.

To calculate LAC in constant dollars, a discount rate that accounts for inflation over the system life is determined. This rate, denoted by r', is given by:

$$r' = \frac{(1 + r)}{(1 + g)} - 1 \qquad [9]$$

where g is the annual inflation rate. The r' is then used in the CRF equation to yield a capital recovery factor in constant (base year) dollars:

$$CRF' = \frac{r' \; (1 + r')^N}{(1 + r')^N - 1} \qquad [10]$$

Substituting CRF' for CRF in equation (1) gives:

$$\text{LAC (Constant \$)} = \text{CRF}' \cdot \text{PW} \qquad [11]$$

Further substitution of equation (7) into (11) results in:

$$\text{LAC (Constant \$)} = \frac{\text{CRF}'}{\text{CRF}} \, I_C \cdot \text{FCR} \cdot \text{CRF} + M \, A_{OM} \qquad [12]$$

Combination of equations (2), (6), and (10) results in:

$$\frac{\text{CRF}'}{\text{CRF}} \cdot M = 1 \qquad [13]$$

provided tht g, the annual inflation or escalation rate, is the same for O&M as for the general rate of inflation used in computing r'. This expression, in turn, reduces equation (12) to:

$$\text{LAC (Constant \$)} = \frac{\text{CRF}'}{\text{CRF}} \cdot I_C \cdot \text{FCR} \cdot \text{CCF}' + A_{OM} \qquad [14]$$

Levelized Annual Benefits

The comparison of the energy cost savings of the PV system to the levelized annual cost is accomplished by computing the levelized annual benefits (LAB) for the energy savings. LAB is inherently a function of present and projected energy prices and may be expressed by

$$\text{LAB (Constant \$)} = \frac{\text{CRF}'}{\text{CRF}} \cdot M_f \cdot P_0 \cdot E \qquad [15]$$

where E represents the annual energy saved by the solar system, M is an energy savings multiplier, which is defined as the levelized value of an escalating cost stream which accounts for the rate of energy price escalation over the lifetime of the system, and P_0 is the energy price in year zero. In actual practice the appropriate utility rate schedule is applied with the savings determined by the difference of the electric bills computed with and without the PV system.

The multiplier M_f is a function of energy price escalation rate (f), system lifetime (N), and discount rate (r), and is expressed as*

$$M_f = \frac{r(1+f)}{r-f} \frac{(1+r)^N - (1-f)^N}{(1+r)^N - 1}$$

The economic viability of a system can be measured by comparing the levelized annual cost to the levelized annual benefits. If the levelized annual benefits exceed the levelized annual cost, the system is economically workable. The break-even system cost occurs when LAC and LAB are equal.

_____

*When r = f:

$M = CRF \cdot N$

The energy price in year zero (P_0) is related to the energy price in constant (base year) dollars per energy unit (p) through the expression

$$P_0 = p \frac{1+f}{1+g}$$

where p is the number of years from the base year to year zero.

C-1 Doane, J. W., et. al: The Cost of Energy from Utility-Owned Solar Electric Systems, Report JPL 5040-29, Jet Propulsion Laboratory, June 1976.